Freehold

ROYALTY TRUST

ANNUAL REPORT 2005

+ Freehold Royalty Trust is a publicly traded **energy trust**. We receive income from over 22,000 **oil and gas** wells in Canada, and 80% of our production comes from **royalty interests**.

So what's new?

This is new

The Petrovera acquisition added:

+ 1 million gross acres of royalty land

+ 3,800 boe per day of royalty production

+ 12.9 million boe of reserves

On May 10, 2005, Freehold completed the acquisition of Petrovera Resources, a general partnership, for $352 million. The acquisition solidifies Freehold's position as the only oil and gas trust in Canada focused primarily on royalty interests.

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HIGHLIGHTS

FINANCIAL

($000s, except unit data)	**2005**	2004	Change
Gross revenue	**136,914**	78,491	74%
Operating income	**126,793**	69,654	82%
Net income	**58,346**	36,892	58%
Per Trust Unit, basic and diluted *($)* [1]	**1.36**	1.17	16%
Funds generated from operations	**118,034**	64,313	84%
Per Trust Unit *($)* [1]	**2.76**	2.04	35%
Distributions declared	**84,810**	54,490	56%
Per Trust Unit *($)* [2]	**1.92**	1.73	11%
Development expenditures	**7,982**	5,823	37%
Long-term debt	**107,000**	27,000	296%
Unitholders' equity	**399,471**	164,822	142%
Trust Units outstanding *(000s)*	**49,032**	31,544	55%
Weighted average *(000s)*	**42,812**	31,488	36%

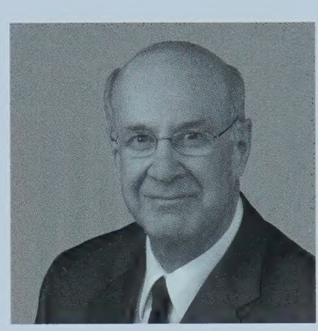
OPERATING

Production			
Oil *(bbls/d)*	**4,488**	3,594	25%
NGLs *(bbls/d)*	**345**	283	22%
Natural gas *(Mcf/d)*	**16,821**	10,270	64%
Oil equivalent *(boe/d)* [3]	**7,636**	5,588	37%
Average sales price *($/boe)* [3]	**48.53**	37.91	28%
Operating netback *($/boe)* [3]	**45.49**	34.05	34%
Reserves *(Mboe)* [3, 4]	**30,530**	21,163	44%
Land holdings *(gross acres)*	**2,005,945**	1,067,029	88%
Undeveloped land *(gross acres)*	**555,171**	291,729	90%

1 Based on the weighted average number of Trust Units outstanding during the year.
2 Based on the number of Trust Units issued and outstanding at each record date.
3 To provide a single unit of production for analytical purposes, natural gas production and reserve volumes are mathematically converted to equivalent barrels of oil (boe) at a ratio of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The boe ratio approximates an equivalent energy value, useful for comparative measures, but may not accurately reflect individual product values.
4 Net proved plus probable reserves, evaluated under National Instrument 51-101.

MESSAGE FROM THE PRESIDENT

As we enter our tenth year of operations, I am pleased to report on our 2005 results and share with you the opportunities we see for Freehold in the years ahead.



David J. Sandmeyer
President and CEO

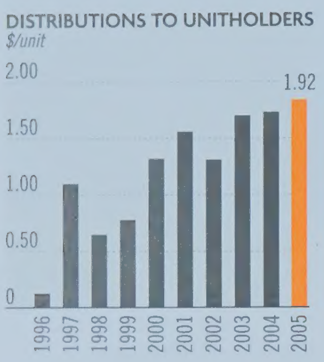
Freehold achieved record financial and operating performance in 2005, driven by a 37% increase in oil and gas production and a 28% increase in average price realizations. Net income rose 16% and funds generated from operations rose 35%, on a per Trust Unit basis. As well, operating costs and general and administrative expenses were lower on a per barrel of oil equivalent (boe) basis, reflecting the benefit of additional royalty production acquired in 2005.

While credit for our strong performance is in part due to high commodity prices, our royalty production grew dramatically in 2005, through the acquisition of the Petrovera Resources Partnership in May. At $352 million, the acquisition was the largest transaction in our history (even larger than our initial public offering in 1996). It gave our production an immediate 65% boost, adding 2,465 boe per day (annualized) to 2005 production. Unitholders also benefited from direct exposure to commodity prices, as we continued to leave our production 100% unhedged.

Our net reserves grew 44% year over year, as the Petrovera properties added 12.9 million boe of net proved plus probable reserves. We replaced 428% of 2005 production through acquisitions and development activities (excluding technical revisions and economic factors), at an average cost of $26.02 per boe. The relatively high cost is justified by the high netback royalty production with no future capital requirements. Our net asset value (discounted at 10%) increased 55% to $13.85 per Trust Unit. Based on the evaluator's forecast of 2006 production, our calculated reserve life index is 9.9 years compared with 10.6 years at the end of 2004. Natural gas reserves now account for approximately 37% of boe reserves, up from 29% last year.

To finance the Petrovera acquisition, we issued 17.4 million Trust Units at $15.55 per Trust Unit, raising $259 million; the remainder was funded through our credit facilities. With the additional equity we issued, we have a larger market capitalization, which has provided enhanced liquidity for our Unitholders. Our market capitalization grew to $922 million by year-end, which led to Freehold's inclusion in the S&P/TSX Composite Index in December.

Distributions paid or payable to Unitholders reached a record $1.92 per Trust Unit in 2005, including a special payment of $0.08 per Trust Unit in respect of excess taxable income earned in 2005. Over the course of the year, Unitholders saw three distribution increases (a 50% increase) and our Trust Unit price appreciated 8%, generating a 2005 total return of 20%. Since inception, we have returned $12.20 in cumulative distributions, generating a total return of 499% (based on our $10 initial offering price).



Distributions reached a record $1.92 per Trust Unit in 2005, representing 72% of funds generated from operations.

Petrovera acquisition an excellent strategic fit

The Petrovera acquisition was very strategic for Freehold. It is accretive to funds generated from operations, production, reserves and net asset value, on a per Trust Unit basis. It adds critical mass to enhance the stability of distributions over the long term – from royalty interest assets that are a very good fit with our existing portfolio.

The acquisition doubles our royalty land holdings and broadens our asset base into the Peace River Arch region of the Western Canadian Sedimentary Basin. The properties include interests in approximately 8,000 wells, nearly half of which overlap with Freehold's existing wells and production units. We also gain a new property base offshore Lake Erie, Ontario. Natural gas from this operation receives a premium price due to its close proximity to major southern Ontario markets.

Synergies and economies of scale have reduced general and administrative costs on a per boe basis. Our overall operating expenses per boe have also declined, as the Petrovera assets are royalty interests, which incur no operating costs.

Excellent future development potential

With the Petrovera acquisition, our undeveloped land holdings increased to approximately 555,200 gross acres. This undeveloped land consists of non-producing spacing units that have substantial infill development drilling potential.

In this environment of high commodity prices, even developed lands are experiencing significant infill drilling activity, as operators reduce well spacing to capture maximum value from their resource opportunities. Industry-wide, 24,800 wells were drilled in 2005, just shy of the record 25,000 wells drilled in 2004.

Drilling on Freehold's lands mirrored this activity, with 1,001 gross wells drilled, including 311 wells on the Petrovera lands. This resulted in 25 equivalent net royalty wells and 9.1 net working interest wells.

In the current pricing environment, industry activity levels are anticipated to remain robust, with more than 25,000 new wells forecast to be drilled in 2006. We expect that drilling on our royalty lands will likewise remain at high levels. With interests in two million gross acres of land throughout the Western Canadian Sedimentary Basin, Freehold will continue to be a "window on the Basin" in terms of industry activity levels going forward.

Industry fundamentals remain strong

In 2005, WTI averaged US$56.56 per barrel, the highest level ever. Natural gas prices were also high, averaging $8.48 per thousand cubic feet, an increase of 25% over 2004. Due to a global surplus of heavy crude and a lack of upgrading facilities, we have seen a significant widening of heavy oil differentials (discounts from WTI). In 2005, the differential averaged $23.90, well above the historical average of $10.79 per barrel since inception of the Trust. The good news is that oil prices overall are higher, so the negative impact of heavy oil differentials has been somewhat muted.

The fundamental outlook for oil and gas producers is positive for 2006 and through the remainder of the decade. World demand for oil and natural gas continues to grow, dominated by the need for energy to fuel economic growth in developing countries like China and India.

Supply remains tight and there is a very limited supply cushion, which is a particular concern given that political issues, performance issues, and weather-related issues can impact supply unexpectedly. The sensitive nature of the supply-demand balance was evidenced in the fall of 2005, when hurricane damage to oil platforms, refineries, and natural gas production facilities sent energy prices soaring to all-time highs.

Record industry activity levels have resulted in intense competition for land, oilfield supplies and services, and people, causing inflationary pressures throughout the oil and gas sector. The industry is experiencing a shortage of experienced professionals and skilled trades, which has created a bottleneck in bringing new production on stream. Finding and development costs – as well as operating costs – are on the rise. As 80% of our production is from royalties, we are somewhat sheltered from these inflationary pressures.

Royalty focus adds value in any price environment

Our greatest asset continues to be the value of our royalty lands. Our focus on royalty interests is key to our adding value in any price environment. We are seeing increased drilling activity on our royalty lands, which helps offset the depletion of our production and reserves. At the same time, we have little exposure to rising operating and capital costs.

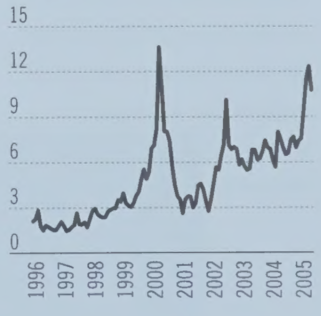
We do not require high levels of capital investment to maintain our asset base. As a royalty interest owner, we do not pay any of the capital costs to drill and equip the wells for production. Other industry operators pay those up-front costs and then pay a royalty to us on the resulting production – before the deduction of operating expenses. Nor do we incur costs for maintenance and reclamation of wells drilled on our royalty lands.

About 20% of our production comes from working interest properties, and on these properties, we do incur capital expenditures. Since 1997, our development expenditures on working interest properties have amounted to $33.4 million – or approximately 7% of cumulative funds generated from operations.

WTI CRUDE OIL PRICES
US$/bbl

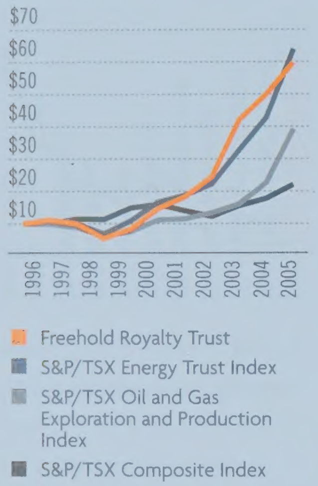
In 2005, average WTI oil prices were 37% higher than in 2004.

AECO NATURAL GAS PRICES
Cdn$/Mcf



In 2005, average AECO natural gas prices were 25% higher than in 2004.

CUMULATIVE VALUE OF
$10 INVESTMENT



Assuming reinvestment of all distributions ($12.20 per Trust Unit) a $10 investment in our initial public offering had a value of $60 at December 31, 2005.

Distribution outlook

We enter 2006 with strong production volumes as the full benefit of the Petrovera acquisition is realized. Our 2006 forecast calls for commodity prices to average US$60.75 per barrel for WTI oil and Cdn$8.80 per Mcf for AECO natural gas. We anticipate that light/heavy oil differential prices will widen during 2006, to average Cdn$30 per barrel. Based on these assumptions, and average production of 8,500 boe per day, our estimate of cash distributions for 2006 is $2.16 per Trust Unit, giving us a payout ratio of about 90%.

At the Board's discretion, any excess income available for distribution will be directed toward repayment of long-term debt and improvements in working capital. We expect that this policy will continue in order to allow us to reduce our long-term debt.

Our strategy remains consistent

We are not driven by absolute growth objectives. Our primary goal is to extend cash distributions over the long term by actively managing our assets to sustain production and extend reserve life, without diluting our Unitholders. Our strategy to achieve this is to:

- maintain an aggressive audit program to ensure that royalties are correctly calculated and paid;
- pursue development opportunities to optimize reserves and production on our working interest properties;
- acquire appropriate assets with a bias toward royalty interests; and
- maintain a conservative approach to debt management to provide maximum financial flexibility with respect to acquisitions, development capital expenditures, and maintaining distributions.

These strategies are supported by an experienced management team who have managed Freehold's original assets for more than two decades.

Acknowledgements

In closing, I would like to acknowledge the efforts of the employees of Rife Resources Ltd., who manage the assets of Freehold. This team worked exceptionally hard and put in many long hours to complete the Petrovera acquisition, while ensuring other important work was done.

I would like to thank our Board of Directors for their continued guidance and support, and for the significant time they dedicate to Freehold. Our independent directors helped conduct appropriate due diligence on the Petrovera acquisition and undertook a detailed review of our governance practices in 2005 to ensure they remain consistent with evolving best practices.

Finally, I would like to thank you, our Unitholders, for your continued support. We look forward to continuing to provide you with solid returns on your investment for many years to come.

D J Sandmeyer

David J. Sandmeyer
PRESIDENT AND CHIEF EXECUTIVE OFFICER
MARCH 14, 2006

Officers (from left to right): Mike Okrusko, Vice-President, Land; Frank George, Vice-President, Exploitation; David Sandmeyer, President and CEO; Bill Ingram, Vice-President, Production; Darren Gunderson, Controller; Joe Holowisky, Vice President, Finance and Administration, CFO and Secretary.

MESSAGE FROM THE CHAIR

Accountability to Unitholders through responsible governance.

William W. Siebens
Chair of the Board

That was the title of the corporate governance report in Freehold's 1996 annual report, published after our initial public offering, evidence that governance has always been important to Freehold. A majority of our Board members are independent directors, and the position of the Chair has been separate from that of the CEO since the Trust's inception. Our three committees of the Board are made up entirely of independent directors and each committee conducts its business according to a written mandate approved by the Board.

The Board has responsibility for overall stewardship with a view to preserving and enhancing the underlying value of the Trust. The Board discharges its responsibility by reviewing, discussing and approving the Trust's strategic planning and organizational structure, and supervising management, including retention of the Manager. Management of the business within this process and structure is the responsibility of the CEO and the Manager.

The Board is committed to maintaining a high standard of governance, recognizing that governance practices continue to evolve. In 2005, new governance guidelines and reporting requirements were published by the Canadian Securities Administrators, and we undertook to review and enhance our governance practices in light of these new guidelines.

The Board adopted a written mandate, and developed position descriptions for the directors, the Board Chair and the CEO. We instituted formal in-camera sessions of the independent directors in November 2005, and these will be scheduled as part of every Board meeting in the future.

We implemented two new policies, which will be key tools in the ongoing delivery of good governance practices. And to ensure that these policies were communicated and understood throughout our organization, the Manager hosted a town hall presentation for employees. Our code of conduct and conflict of interest policy is designed to ensure that the business and affairs of the Trust are conducted with the highest ethical standards of business conduct. Directors and officers of Freehold, as well as employees of the Manager, are required to review and sign-off on this policy annually. Our whistleblower policy is intended as a clear statement that if any wrongdoing by Freehold or any of its directors, officers or employees or by any of its consultants or suppliers is identified and reported to Freehold, it will be dealt with expeditiously, thoroughly investigated and remedied.

In keeping with our commitment to the highest possible standards of openness, honesty and accountability, we have posted these governance documents on Freehold's website. The Board invites feedback from our Unitholders and other stakeholders. Any person who has a concern about Freehold's governance, business conduct or financial practices may communicate that concern to the Board.

In 2005, Freehold engaged an independent human resources consulting firm to conduct a custom-designed peer survey of director compensation. The results indicated that Freehold's director compensation was not competitive with the survey group. Based on the recommendation of the Governance Committee, directors' compensation was increased effective January 1, 2006.

I would like to acknowledge management's efforts to keep the directors informed about important issues. Concise and timely information enables the Board to focus on strategic issues around the boardroom table. I would also like to thank my fellow directors for the leadership, expertise, and commitment they bring to the Freehold Board.

On behalf of the Board of Directors,

William W. Siebens
Chair of the Board

INDEPENDENT DIRECTORS

Five independent directors are elected annually by the Unitholders.

WILLIAM W. SIEBENS

Chair of the Board; Member, Governance Committee

Bill Siebens is President and CEO of Candor Investments Ltd. (Calgary), a private energy and investment corporation. He currently serves as a director of the Fraser Institute. He brings special expertise to Freehold with his knowledge of the Trust's royalty lands as a portion of these lands were previously owned by Siebens Oil & Gas Ltd.

D. NOLAN BLADES

Chair, Audit Committee; Chair, Reserves Committee; Member, Governance Committee

Nolan Blades is President of Sunny Gables Holdings Ltd. (Calgary) and a Professional Engineer with extensive experience in the oil and gas industry. Mr. Blades was President and CEO of Pursuit Resources Corp. from 1993 to 2000. He is currently Chairman of Real Resources Inc., and is a director of Gemini Corporation and Canoro Resources Ltd.

MANAGEMENT DIRECTORS

Two management directors are appointed by the Manager.

TULLIO CEDRASCHI

Director

Tullio Cedraschi is President and CEO of the CN Investment Division (Montreal), which manages one of the largest pension funds in Canada. He is currently a director of the Toronto Stock Exchange, Western Oil Sands Inc. and Helix Investments (Canada) Inc. He is Governor Emeritus of McGill University, and Governor of the National Theatre School of Canada. He holds an MBA from McGill University.

HARRY S. CAMPBELL Q.C.

Member, Reserves Committee

Harry Campbell is Managing Partner of the law firm Burnet, Duckworth & Palmer LLP (Calgary). He was admitted to the Alberta Bar in 1974 and has extensive experience with Canadian oil and gas transactions and international petroleum and natural gas matters. Mr. Campbell is currently a director of Delphi Energy Corp. and The Cathay Investment Fund Limited.

PETER T. HARRISON

Member, Audit Committee; Member, Reserves Committee

Peter Harrison is Senior Vice-President of Montrusco Bolton Inc. (Montreal). Mr. Harrison has more than 26 years of investment experience and previously managed Canadian Equities for the CN Investment Division. Mr. Harrison is currently a director of Daylight Energy Trust. He holds a Bachelor of Commerce degree from McGill University, an MBA from the University of Western Ontario and is a Chartered Financial Analyst.

DR. P. MICHAEL MAHER

Chair, Governance Committee; Member, Audit Committee

Michael Maher is a Professor and former Dean of the Haskayne School of Business, University of Calgary. He currently serves as a director of EPI Environmental Technologies Inc. and Wellpoint Systems Inc. He has a Bachelor of Science degree in Engineering from the University of Saskatchewan; an MBA from the University of Western Ontario; a PhD from Northwestern University; a Doctor of Commerce (honoris causa) degree from St. Mary's and is a Professional Engineer.

DAVID J. SANDMEYER

President and CEO and Director

David Sandmeyer is President and CEO of Freehold Resources Ltd. (Calgary), President of Rife Resources Ltd. and President of Canpar Holdings Ltd. Prior to joining Rife in 1982, he held senior positions with Amoco Canada Petroleum Company Limited. He is a former Governor of the Canadian Association of Petroleum Producers. A graduate of the University of Saskatchewan, he holds a Bachelor of Science degree in Mechanical Engineering and is a Professional Engineer.

+ ENVIRONMENT, HEALTH AND SAFETY

Operating Partners

Freehold is a member of the Canadian Association of Petroleum Producers (CAPP). We promote the development and use of a systematic approach to continuously improve environment, health, safety and social performance. We encourage our operators to participate and excel in the CAPP Stewardship Program, by aligning their operations with industry best practices and communicating clearly that meeting or exceeding regulatory requirements is expected.

We do not operate any of our oil and gas assets, nor do we have any employees. The employees who manage the affairs of Freehold are employees of Rife Resources Ltd., a private oil and gas company that manages production of more than 23,000 boe per day on behalf of three entities, including Freehold. Rife has a comprehensive environment, health and safety program to protect the health and safety of its employees, contractors and the public.

Canadian GHG Challenge Registry©

The Canadian GHG Challenge Registry© is Canada's only voluntary publicly accessible national registry of greenhouse gas baselines, targets, and reductions. The primary objective of the Registry is to challenge registrants from all economic sectors and geographic regions to demonstrate meaningful actions which contribute towards the reduction of Canada's greenhouse gas emissions. The benefits of applying these standards include the use of international best practices, promotion of the environmental integrity of greenhouse gas claims, and management of greenhouse gas risks. Rife has participated in the registry since 1995, achieving gold status for 2004 and 2005.

Partnerships in Health and Safety Program

Alberta Human Resources and Employment established the Partnerships in Health and Safety Program to foster a culture where health and safety becomes an integral part of every workplace. A Certificate of Recognition (COR) is given to employers who develop health and safety management programs that meet established standards, including an extensive, external audit.

In 2005, Rife completed an independent safety audit, exceeding the required audit score of 80%, and has applied for a COR. Rife will continue to support the Partnerships program which requires an external audit every three years.

Reclamation Fund

In 1996, we established a reclamation fund to ensure that required funds were available for future reclamation of working interest wells and facilities once they have reached the end of their economic life. We have no reclamation responsibilities on our royalty assets as these are the responsibility of the working interest owners. We contributed $422,000 in cash and interest to the fund during 2005 and withdrew $104,000, which was spent on reclamation activities. At December 31, 2005, the fund had a balance of $2 million.

UNDERSTANDING OUR ASSETS

Our diversified asset base consists primarily of royalty interests, which provides income from the production and sale of crude oil, natural gas, natural gas liquids and potash. We receive revenue from more than 22,000 oil and gas wells, the majority of which are located in Alberta.

LAND HOLDINGS

Our land holdings encompass two million gross acres, throughout western Canada and in southern Ontario. The Petrovera acquisition in 2005 added 943,965 gross acres of royalty land, including 264,597 gross acres of undeveloped land. Approximately 9% of the acquired lands overlapped with our existing royalty acreage.

At December 31, 2005, our undeveloped land position totalled 555,171 gross acres, which was valued at $14.1 million by Seaton-Jordan & Associates Ltd., an independent consulting firm.

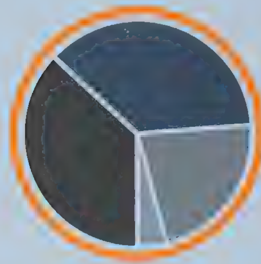
LAND HOLDINGS BY PROVINCE

(gross acres) [1]	**2005**	2004	2003
Alberta	**1,207,929**	699,556	642,092
Saskatchewan	**463,948**	339,303	340,475
Ontario	**244,447**	0	0
British Columbia	**81,559**	25,946	25,946
Manitoba	**8,062**	2,224	2,224
Total	**2,005,945**	1,067,029	1,010,737
Undeveloped land	**555,171**	291,729	242,205

1 Gross acres represents the total number of acres in which we have an interest.

On a boe basis, 63% of our 2005 production was derived from oil and natural gas liquids, and 37% was natural gas.

2005 PRODUCTION PROFILE



PRODUCTION

Oil and gas production increased 37% in 2005, with the Petrovera acquisition contributing approximately 3,800 boe per day from May 10 through December 31, 2005. Royalty production rose 59% while working interest production declined 7%. Royalty interest properties contributed 77% of total production in 2005.

PRODUCTION SUMMARY

(boe/d)	**2005**	2004	2003
Royalty interest properties	**5,885**	3,711	3,972
Working interest properties	**1,751**	1,877	1,845
Total	**7,636**	5,588	5,817

DRILLING

With 1,001 new wells, 2005 was a record year for drilling on our lands.

The continued high level of drilling activity on our royalty lands is a strong indication of the ongoing development potential that exists on these lands. In 2005, operators drilled a total of 884 gross royalty wells, including 310 royalty wells on the Petrovera lands. On an equivalent net basis, this resulted in 25 wells, twice the number of equivalent net wells drilled in 2004. Our royalty interests in these wells, which vary from less than 1% to 22.5%, are not comparable to net wells for working interest properties, because we are not responsible for the capital or operating costs for these wells and associated production.

On our working interest properties, operators drilled 117 gross (9.1 net) wells, an increase of 69% over last year. The 100% success rate reflects the conservative nature of our capital investment program, which excludes participation in high risk exploratory drilling.

DRILLING BY PROVINCE

(gross wells) [1]	**2005**		2004		2003	
	Royalty Interest [2]	**Working Interest**	Royalty Interest	Working Interest	Royalty Interest	Working Interest
Alberta	**739**	**103**	541	75	380	48
Saskatchewan	**141**	**6**	130	2	196	3
British Columbia	**4**	**8**	0	12	0	23
Manitoba	**0**	**0**	0	1	0	0
Ontario	**0**	**0**	0	0	0	0
Total	**884**	**117**	671	90	576	74

1 Gross wells is the number of wells in which we have a royalty interest or a working interest.
2 Includes drilling on Petrovera lands from January 1, 2005, the effective date of the acquisition.

ROYALTY INTEREST PROPERTIES

Freehold is one of the largest holders of royalty interests in Canada. Over 90% of our income comes from royalties paid on gross production revenue. We have gross overriding royalty interests in approximately 1,260,300 gross acres, and our mineral title lands cover approximately 548,400 gross acres. We receive royalty payments from over 200 operators.

ROYALTY INTEREST PROPERTIES SUMMARY

	2005	2004	2003
Land holdings *(gross acres)*	**1,808,704**	867,155	816,773
Average royalty interest *(%)*	**1.2**	0.8	0.8
Oil and gas reserves (net)			
Proved *(Mboe)*	**15,648**	9,617	10,250
Proved plus probable *(Mboe)*	**24,018**	14,332	14,726
Average daily production			
Oil and NGL *(bbls/d)*	**3,469**	2,423	2,624
Natural gas *(Mcf/d)*	**14,501**	7,726	8,089
Oil equivalent *(boe/d)*	**5,885**	3,711	3,972
Potash *(tonnes/d)*	**9.7**	7.6	7.6
Wells drilled *(gross)*	**884**	671	576
Gross revenue *($000s)* [1]	**107,428**	52,677	49,903
Operating netback *($/boe)*	**50.01**	38.78	34.42

1 Includes potash revenue, sulphur revenue and other.

WORKING INTEREST PROPERTIES

We also hold various working interests in 88 oil and gas properties, encompassing 197,241 gross (22,003 net) acres throughout western Canada. In 2005, four properties in Alberta (Hayter, Pembina, Ribstone/Chauvin, and Pouce Coupe) contributed 59% of our working interest production.

WORKING INTEREST PROPERTIES SUMMARY

	2005	2004	2003
Land holdings *(gross acres)*	**197,241**	199,874	193,964
Oil and gas reserves (net)			
Proved *(Mboe)*	**4,763**	5,061	5,187
Proved plus probable *(Mboe)*	**6,511**	6,831	7,327
Wells drilled			
Gross	**117**	90	74
Net	**9.1**	5.4	6.9
Average daily production			
Oil and NGL *(bbls/d)*	**1,364**	1,454	1,381
Natural gas *(Mcf/d)*	**2,320**	2,544	2,783
Oil equivalent *(boe/d)*	**1,751**	1,877	1,845
Development expenditures *($000s)*	**7,982**	5,823	5,894
Gross revenue *($000s)*	**29,486**	25,814	23,263
Operating netback *($/boe)*	**30.30**	24.71	22.08

+ QUESTION **Why are royalty interests significantly more valuable than conventional working interests?**

Royalty interests provide revenue without incurring any of the working interest owner's costs. These costs can be quite significant, for example:

1. Finding, development and on-stream costs

Working interest owners must acquire land, conduct seismic programs and determine the geological potential of lands before drilling. On our royalty lands, we don't pay any of the capital costs to find, drill and equip the wells for production. Other third party operators pay those up-front costs and then pay a royalty to us on the revenue from the resulting production. This royalty is a percentage of gross production revenue and comes off the top – before the deduction of other expenses. The royalty rates vary from less than 1% (for some gross overriding royalties) to 22.5% (for some mineral title royalties) and are set out in each individual lease and contract agreement.

2. Royalties to the owner of the mineral rights

Working interest owners must pay a royalty to the owner of the mineral rights. As a royalty interest owner, we don't pay these expenses.

3. Operating costs

Working interest owners incur ongoing costs to operate producing wells, and they also incur maintenance costs such as downhole stimulations and workovers to extend the productive life of a well. As a royalty interest owner we are not responsible for these costs.

4. Abandonment and reclamation costs

Royalty interest owners are not responsible for any of the costs to abandon the wells and reclaim the land after the wells have reached the end of their productive life.

All of the above costs are rising throughout the industry.

Because royalty interest owners do not pay any of these costs, on a value basis this makes a royalty interest barrel worth significantly more than a working interest barrel. These differences are illustrated in the netback analysis provided on page 39 of this annual report.

These attributes also make royalty assets attractive to acquire, thus commanding a higher market price.

+ QUESTION What future drilling opportunities exist on Freehold's lands?

Freehold's gross land holdings as at December 31, 2005 encompass two million acres of which we consider 555,171 gross acres to be undeveloped. Of this amount, 154,571 gross undeveloped acres are in Ontario, the offshore Lake Erie property acquired through the Petrovera acquisition in 2005. The rest is located in western Canada (British Columbia, Alberta, Saskatchewan and Manitoba), and consists primarily of undrilled spacing units. Development potential exists on our lands by increasing the well density with additional vertical or horizontal wells.

Royalty Interest Properties

Activity on our royalty lands has historically mirrored industry activity. This means when the industry is busy drilling, the high level of activity is generally reflected in our drilling statistics. Industry activity levels are anticipated to remain strong in 2006, with more than 25,000 wells forecast to be drilled in western Canada. We expect that drilling on our royalty lands will likewise remain at high levels.

The working interest owners (operators) are not required to advise us, the royalty recipient, of their plans. Therefore we do not have an assessment of the likelihood of future plans for drilling on individual leases. Our royalty payors include some of North America's largest and most active oil and gas companies. In the current commodity price environment, we believe these operators are actively examining their properties to ensure they take full advantage of attractive economic prospects.

The future development potential was enhanced with the Petrovera acquisition in 2005. Our analysis shows that, overall, the acquired lands are less densely drilled than Freehold's royalty lands prior to the acquisition. We examined the historical drilling on the Petrovera lands, the current well density (in other words the maturity of the fields) as well as the activity of the operators, land expiry issues and the geographic location of lands. We compared these factors against our own experience, where more than 4,700 wells have been drilled on our royalty lands over the past nine years, adding reserves and production at no cost to us. Recent drilling activity on the acquired lands has been significant, with 900 wells drilled in the last three years. This drilling activity is further evidence of the development potential that may exist on these lands.

As at December 31, 2005, there were 92 (4.6 equivalent net) licensed drilling locations on our royalty lands, compared with 41 (1.3 equivalent net) locations at the same time last year, signalling a very strong start to 2006.

Working Interest Properties

In 2006, we will spend approximately $6 million on various working interest properties. At Hayter, we expect to spend $3.5 million to tie-in new production from the 2005 drilling program, expand water handling facilities, and drill 11 (2.6 net) infill locations. The remaining capital will be spent on development activities in Southeast Saskatchewan and on miscellaneous properties. We anticipate that development activities in 2006 will add approximately 190 boe per day of production.

+ RESERVES

This annual report contains a summary of the reserves data and other information that has been prepared and filed with securities regulatory authorities in accordance with National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities (NI 51-101).

The board of directors has, on the recommendation of the Reserves Committee, approved the content of the reserves data. The complete report has been filed with regulatory authorities and is available on SEDAR at www.sedar.com.

Summary of Reserves

Our oil and gas reserves were independently evaluated by Trimble Engineering Associates Ltd. At December 31, 2005, reserves were assigned to 19,468 wells. Net reserves totalled 30.5 million boe, up 44% from year-end 2004.

SUMMARY OF NET RESERVES [1]

	Proved Developed Producing	Proved Developed Non-Producing	Proved Undeveloped	Total Proved	**Proved Plus Probable**
Light and medium oil *(Mbbls)*	4,722	0	0	4,722	**6,641**
Heavy oil *(Mbbls)*	6,642	0	239	6,881	**10,813**
Natural gas *(MMcf)*	45,105	131	11	45,247	**68,152**
NGL *(Mbbls)*	1,267	0	1	1,268	**1,717**
Total *(Mboe)*	**20,149**	22	**241**	**20,412**	**30,530**

1 Columns may not add due to rounding.

RECONCILIATION OF NET OIL AND GAS RESERVES [1]

	Net Proved *(Mboe)*	Net Probable *(Mboe)*	**Net Proved Plus Probable** *(Mboe)*	**Net Present Value** [2] *($000s)*
December 31, 2004	14,678	6,485	**21,163**	**292,247**
Extensions and improved recovery	413	500	**913**	**35,187**
Technical revisions	158	(1,423)	**(1,265)**	**(15,396)**
Discoveries	16	16	**32**	**1,450**
Acquisitions [3]	8,323	4,566	**12,889**	**224,521**
Dispositions	(27)	(7)	**(35)**	**(385)**
Economic factors	32	28	**60**	**276,887**
2005 production	(3,181)	(46)	**(3,227)**	**(71,679)**
December 31, 2005	20,412	10,118	**30,530**	**742,832**
Change over prior year	5,734	3,633	**9,367**	**450,585**

1 Columns may not add due to rounding.
2 Net present value of proved plus probable reserves based on forecast prices and costs, before tax, including Alberta Royalty Credit, discounted at 10%. Based on the December 31, 2005 escalated oil and gas price forecasts by an independent qualified reserves evaluator.
3 Petrovera Resources, effective January 1, 2005.

The present value of our net proved plus probable oil and gas reserves, discounted at 10%, is $743 million. This represents a 154% increase from 2004, which is primarily related to increased future price expectations and reserves acquired during 2005. The present value is based on the December 31, 2005 reserves and escalated oil and gas price and exchange rate forecasts by an independent qualified reserves evaluator.

NET PRESENT VALUE[1]

		Discounted at		
($000s)	0%	5%	**10%**	15%
Proved				
Developed producing	982,206	694,386	**555,865**	472,437
Developed non-producing	1,228	1,139	**1,062**	995
Undeveloped	4,529	3,556	**2,879**	2,389
Total proved	987,963	699,080	**559,806**	475,822
Probable	520,092	275,641	**183,026**	136,705
Proved plus probable	**1,508,055**	**974,721**	**742,832**	**612,527**

1 Forecast prices and costs, before tax, including Alberta Royalty Credit. Based on the December 31, 2005 escalated oil and gas price forecasts by an independent qualified reserves evaluator. Columns may not add due to rounding.

NET PRESENT VALUE OF RESERVES BY PRODUCT TYPE[1]

($000s)	Total Proved	**Proved Plus Probable**
Light and medium crude oil	146,307	**186,807**
Heavy oil	187,029	**258,500**
Natural gas	226,470	**297,526**

1 Forecast prices and costs, before tax, including Alberta Royalty Credit, discounted at 10%. Based on the December 31, 2005 escalated oil and gas price forecasts by an independent qualified reserves evaluator.

FORECAST PRICES USED IN ESTIMATES

as at December 31, 2005

	Oil				Natural Gas	Natural Gas Liquids			Inflation Rate	Exchange Rate
						FOB Field Gate				
Year	WTI Cushing Oklahoma *(US$/bbl)*	Edmonton Par Price 40° API *(Cdn$/bbl)*	Hardisty Heavy 12° API *(Cdn$/bbl)*	Hardisty Bow River 24.9° API *(Cdn$/bbl)*	AECO 30 Day Spot *(Cdn$/ MMBtu)*	Propane *(Cdn$/bbl)*	Butane *(Cdn$/bbl)*	Pentane *(Cdn$/bbl)*	*(%/year)*	*(US$/Cdn$)*
Forecast										
2006	60.81	70.07	37.07	47.27	11.58	39.25	47.01	71.77	2.5	0.85
2007	61.61	70.99	37.29	47.79	10.84	39.76	47.62	72.71	2.5	0.85
2008	54.60	62.73	34.23	43.23	8.95	35.14	42.08	64.25	2.5	0.85
2009	50.19	57.53	32.27	40.28	7.87	32.22	38.59	58.92	1.5	0.85
2010	47.76	54.65	31.15	38.65	7.57	30.61	36.66	55.97	1.5	0.85
Thereafter, per year	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	0.85

Based on net reserves as at December 31, 2005 and the evaluator's forecast of 2006 net interest production, our proved plus probable reserve life index is 9.9 years.

RESERVE LIFE INDEX (RLI) [1]

	Proved Producing	Total Proved	**Proved Plus Probable**
Net reserves *(Mboe)* [2]	20,149	20,412	**30,530**
Net production *(Mboe)* [2]	2,735	2,771	**3,094**
RLI *(years)*	7.4	7.4	**9.9**

1 Calculated by dividing the evaluator's forecast of 2006 net interest production into the remaining net interest reserves.
2 Net reserves and production include the principal products (light and medium crude oil, heavy oil and natural gas) and associated gas and natural gas liquids.

RESERVE LIFE INDEX (RLI) BY PRINCIPAL PRODUCT [1]

	Proved Producing	Total Proved	**Proved Plus Probable**
Light and medium oil			
Net reserves *(Mboe)*	4,682	4,682	**6,586**
Net production *(Mboe)*	471	471	**532**
RLI *(years)*	9.9	9.9	**12.4**
Heavy oil			
Net reserves *(Mboe)*	6,642	6,881	**10,813**
Net production *(Mboe)*	1,108	1,138	**1,246**
RLI *(years)*	6.0	6.0	**8.7**
Natural gas			
Net reserves *(Mboe)*	38,925	39,056	**59,671**
Net production *(Mboe)*	5,346	5,384	**6,196**
RLI *(years)*	7.3	7.3	**9.6**

1 Based on principal product type within production group and excludes associated gas and natural gas liquids.

We replaced 428% (2004 – 65%) of annual production through acquisitions and development activities (excluding technical revisions and economic factors). The average cost of net reserve replacement was $26.02 per boe in 2005, compared with $12.88 per boe in 2004. The acquired reserves are mainly royalties which have a greater economic value than working interests and, therefore, command a higher market price. The three-year average cost of reserve replacement is $23.99 per boe. Our three-year average recycle ratio is 1.6.

ANALYSIS OF DEVELOPMENT AND ACQUISITION COSTS [1]

	2005	2004	2003	Three-year results
Development expenditures *($000s)*	**7,982**	5,823	5,894	19,699
Change in future development capital estimates *($000s)*	**235**	(2,593)	3,429	1,071
Net reserve additions by development *(Mboe)*	**945**	817	911	2,673
Development costs *($/boe)* [2]	**8.70**	3.95	10.23	7.77
Acquisition expenditures *($000s)*	**351,705**	12,881	3,386	367,972
Net reserve additions by acquisition *(Mboe)*	**12,889**	434	209	13,532
Acquisition costs *($/boe)*	**27.29**	29.68	16.20	27.19
Total expenditures *($000s)*	**359,687**	18,704	9,280	387,671
Change in future development capital estimates *($000s)*	**235**	(2,593)	3,429	1,071
Net reserve additions by development and acquisitions *(Mboe)*	**13,834**	1,251	1,120	16,205
Development and acquisition costs *($/boe)* [2]	**26.02**	12.88	11.35	23.99

1 Based on net proved plus probable reserves evaluated under NI 51-101.
2 Development costs equal development expenditures plus change in future capital, divided by reserves added.

The recycle ratio is a key measure of the efficiency in which new reserves are added and is indicative of the value created by investment activities as it represents the dollars generated for each dollar invested. In 2005, our recycle ratio was 1.7 times, contributing to a three-year result of 1.6 times. The reserves acquired in 2005 were mainly royalties, which have a greater economic value than working interest reserves, and therefore command a higher market price.

RECYCLE STATISTICS

($/boe, except as noted)	2005	2004	2003	Three-year results
Operating netback [1]	**45.49**	34.05	30.51	37.56
Development and acquisition costs [2]	**26.02**	12.88	11.35	23.99
Recycle ratio (times) [3]	**1.7**	2.6	2.7	1.6

1 Operating netback is calculated as total revenue, less operating costs and royalties, net of Alberta Royalty Credit, on a per boe basis. Production volumes used to calculate operating netback include working interest production (before deduction of royalty expenses), and royalty interest production.
2 Development expenditures, plus change in future capital, plus acquisition costs, divided by net proved plus probable reserves added through development and acquisition activities.
3 Recycle ratio is calculated as the operating netback divided by the average cost of acquiring and developing new reserves.

NET ASSET VALUE

Net asset value is an estimate of the underlying value of our reserves and undeveloped land, prior to provision for income taxes, interest expense, general and administrative costs and management fees, but taking into consideration estimated royalty expense, operating costs, other income, capital costs and abandonment costs related to working interest properties. Future net revenue estimates are greatly influenced by price forecasts and future reservoir performance.

Using proved plus probable net interest reserves, our net asset value before tax as of December 31, 2005 (discounted at 10%) was $13.85 per Trust Unit, up from $8.92 at year-end 2004. Year-over-year, the major variances in the composition of asset value were increased bank debt, reserves added through the Petrovera acquisition, issuance of additional Trust Units, and higher future price expectations.

NET ASSET VALUE, AS AT DECEMBER 31, 2005 [1]

			Discounted at	
($000s, except unit data)	0%	5%	10%	15%
Present value of oil and gas reserves [2]	1,508,055	974,721	**742,832**	612,527
Present value of potash reserves [3]	47,258	19,520	**11,044**	7,613
Undeveloped land [4]	14,144	14,144	**14,144**	14,144
Reclamation fund	1,964	1,964	**1,964**	1,964
Working capital	16,281	16,281	**16,281**	16,281
Bank debt	(107,000)	(107,000)	**(107,000)**	(107,000)
Net asset value	1,480,702	919,630	**679,265**	545,528
Trust Units outstanding	49,031,581	49,031,581	**49,031,581**	49,031,581
Net asset value per Trust Unit	**30.20**	**18.76**	13.85	**11.13**

1 Columns may not add due to rounding.
2 Evaluated by Trimble Engineering Associates Ltd. and includes Alberta Royalty Credit.
3 Evaluated by Rife Resources Ltd.
4 Evaluated by Seaton-Jordan & Associates Ltd., effective December 31, 2005.

MANAGEMENT'S DISCUSSION AND ANALYSIS

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The following discussion is management's opinion about our consolidated operating and financial results, which include Freehold Resources Ltd., Freehold Royalty Trust and Petrovera Resources (a general partnership) for the year ended December 31, 2005 and previous periods, and the outlook for Freehold based on information available as at March 14, 2006.

The financial information contained herein has been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the years ended December 31, 2005 and 2004 and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This discussion and analysis should be read in conjunction with the audited financial statements and notes contained in this annual report. Additional information about us, including our annual information form, is available on SEDAR at www.sedar.com.

CONVERSION OF NATURAL GAS TO OIL EQUIVALENT

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are mathematically converted to equivalent barrels of oil (boe). We use the international conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio approximates an equivalent energy value at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

NON-GAAP MEASURES

We believe that operating income, netback and funds generated from operations are useful supplemental measures to analyze operating performance, leverage and liquidity. Operating income, which is gross revenue less royalty expense and operating expense, represents the results of operations before general and administrative, interest, taxes and non-cash expenses. Operating netback, which is calculated as average unit sales price less royalties and operating expenses; and investor netback, which deducts administrative and interest expense and income and capital taxes, represent the cash margin for product sold, calculated on a per boe basis. Funds generated from operations is derived from our Consolidated Statements of Cash Flows. It represents cash provided by operating activities, before changes in non-cash working capital. Operating income, netback, and funds generated from operations do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.

FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at March 14, 2006, and contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. These forward-looking statements are made as of the date of this MD&A, and we assume no obligation to update or revise them, except as required pursuant to applicable securities laws.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

Non-Monetary Transactions

In June 2005, the Accounting Standards Board (AcSB) issued Section 3831, Non-Monetary Transactions, which replaces Section 3830 and requires all non-monetary transactions to be measured at fair value unless:

- The transaction lacks commercial substance.
- The transaction is an exchange of a product or property held for sale in the ordinary course of business for a product or property to be sold in the same line of business to facilitate sales to customers other than the parties to the exchange.
- Neither the fair value of the assets or services received nor the fair value of the assets or services given up is reliably measurable.
- The transaction is a non-monetary, non-reciprocal transfer to owners that represent a spin-off or other form of restructuring or liquidation.

The new requirements apply to non-monetary transactions initiated in periods beginning on or after January 1, 2006. Earlier adoption is permitted beginning on or after July 1, 2005. We do not expect the adoption of this standard will have any material impact on our results of operations or financial position.

Financial Instruments – Recognition and Measurement, Hedges, and Comprehensive Income

The AcSB has issued three sections on financial instruments; Section 1530, Comprehensive Income, Section 3855, Financial Instruments - Recognition and Measurement, and Section 3865, Hedges. These three sections will apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. They will require:

- all trading financial instruments to be recognized on the balance sheet and to be fair valued through the income statement;
- all remaining financial assets to be recorded at cost and amortized through the financial statements;
- a new statement for comprehensive income that will include certain gains and losses on translation of assets and liabilities; and
- an update to Accounting Guideline 13 to incorporate the fair value changes currently recorded in the income statement to be recorded through the comprehensive income statement.

We do not expect the adoption of this standard will have any material impact on our results of operations or financial position.

ACCOUNTING POLICIES AND CRITICAL ESTIMATES

Our financial statements are prepared within a framework of GAAP selected by management and approved by our board of directors.

The assets, liabilities, revenues and expenses reported in our financial statements depend to varying degrees on estimates made by management. These estimates are based on historical experience and reflect certain assumptions about the future that are believed to be both reasonable and conservative. The more significant reporting areas are crude oil and natural gas reserve estimation, depletion, impairment of assets, oil and gas revenue accruals, asset retirement obligations, and future income taxes. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known.

An estimate is considered a critical accounting estimate if it requires management to make assumptions about matters that are highly uncertain, and if different estimates that could have been used would have a material impact. We continually evaluate the estimates and assumptions. In the normal course, changes are made to assumptions underlying all critical accounting estimates to reflect current economic conditions and updating of historical information used to develop the assumptions. Except as discussed in this Management's Discussion and Analysis, we are not aware of trends, commitments, events, or uncertainties that are expected to materially affect the methodology or assumptions associated with the critical accounting estimates.

Reserve Estimates, Depletion and Ceiling Test

The current estimates of oil and gas reserves and our future capital expenditures are based on an independent evaluation conducted as of December 31, 2005. Reserve estimates are updated once a year (as at December 31) and when a significant acquisition is completed. The reserve and recovery information provided are only estimates. The actual production and ultimate reserves may be greater than or less than the estimates and the differences may be material.

We follow the full cost method of accounting for petroleum and natural gas interests. Oil and gas properties and royalty interests, including the costs of production equipment and future capital costs associated with proved reserves and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. An increase in estimated proved oil and gas reserves would result in a corresponding reduction in the depletion rate. As at December 31, 2005, the depletion calculation included $2.6 million for estimated future development costs associated with proved undeveloped reserves and excluded $14.1 million for the lower of cost and estimated value of unproved lands.

Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties. The ceiling test estimates were reviewed at year-end to ensure that they are reasonable and supportable in light of current economic conditions. The ceiling test, performed as at December 31, 2005, indicated that the undiscounted future net revenues from proved reserves exceed the net book value of the properties. Accordingly no write down of oil and gas properties is required.

Accruals

Freehold follows the accrual method of accounting, making estimates in its financial and operating results. This may include estimates of revenues, royalties, production and other expenses and capital items related to the period being reported, for which actual results have not yet been received. We expect that these accrual estimates will be revised, upwards or downwards, based on the receipt of actual results.

The Trust has no operational control over its royalty lands, and it primarily holds small interests in several thousand wells. Thus, obtaining timely production data from the well operators is extremely difficult. As a result, we use government reporting databases and past production receipts to estimate revenue accruals. The increase in royalty interest production with the Petrovera acquisition in May required a corresponding increase in our revenue accruals. The increase is reflected in higher accounts receivables.

Asset Retirement Obligations

Accounting standards require us to recognize the fair value of an asset retirement obligation in the period in which it is incurred and when a reasonable estimate of the fair value can be made. The fair value of the estimated asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on a unit-of-production method over the life of the reserves. Once the initial asset retirement obligation is measured, it must be adjusted at the end of each period to reflect the passage of time as well as changes in the estimated future cash flows that underlie the obligation.

We have no asset retirement obligations on our royalty income properties. Our asset retirement obligations result from the responsibility to abandon and reclaim our net share of all working interest properties. The net present value of our total asset retirement obligation is estimated to be $4 million (discounted at a weighted average credit adjusted risk free rate of 6.2%), with the undiscounted value being $10.3 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being more than 15 years away.

In determining our asset retirement obligations, we are required to make a significant number of estimates with respect to activities that will occur in many years to come. In arriving at the recorded amount of the asset retirement obligation numerous assumptions are made with respect to ultimate settlement amounts, inflation factors, credit adjusted discount

rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligation also results in an increase to the carrying cost of capital assets. The obligation accretes to a higher amount with the passage of time as it is determined using discounted present values. A change in any one of the assumptions could impact the estimated future obligation and in return, net income. It is difficult to determine the impact of a change in any one of our assumptions. As a result, a reasonable sensitivity analysis cannot be performed.

Future Income Taxes

We follow the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. The actual amount of future income tax may be greater than or less than the estimates and the differences may be material.

INTERNAL CONTROLS AND DISCLOSURE CONTROLS AND PROCEDURES

In compliance with Multilateral Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, Freehold has filed certificates signed by the Chief Executive Officer and the Chief Financial Officer that, among other things, deal with the matter of disclosure controls and procedures. Disclosure controls and procedures are controls and other procedures that are designed to provide reasonable assurance that information required to be disclosed in regulatory filings is recorded, processed, summarized and reported within the time periods specified and include controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management has evaluated the effectiveness of the Trust's disclosure controls and procedures as of March 14, 2006. This evaluation was performed under the supervision of, and with the participation of the Chief Executive Officer and the Chief Financial Officer. It took into consideration Freehold's Disclosure, Insider Trading, Code of Business Conduct and Conflict of Interest, and Whistleblower policies, as well as the functioning of the Manager, the officers, the board of directors, and board committees. In addition, the evaluation covered the processes, systems and capabilities relating to regulatory filings, public disclosures, and the identification and communication of material information. Based on this evaluation management has concluded that Freehold's disclosure controls are effective in ensuring that material information relating to the Trust is made known to management on a timely basis, and is fairly presented in all material respects in this Annual Report.

New rules regarding the reporting on internal control over financial reporting are evolving that will align Canadian financial reporting and certification requirements more closely to those of the U.S. Sarbanes-Oxley Act of 2002. Issuers will be required to establish a suitable control framework, maintain evidence to support management's evaluation and assessment of internal controls, and file a management's report on internal controls. In addition, the issuer's CEO and CFO would be required to make expanded representations on the establishment, design, effectiveness and weaknesses of internal control over financial reporting, as well as any changes to internal controls. The CSA has recently announced that the earliest an internal control reporting instrument would apply is in respect of financial years ending on or after December 31, 2007.

In preparation for certification under the proposed instrument, Freehold has dedicated resources in place to document the internal control environment and evaluate its design and operating effectiveness. These resources have also been actively

engaged with the Company's external auditors and financial advisors in the development and implementation of the activities necessary to meet the certification requirements.

THE MANAGER

Rife Resources Management Ltd. is the Manager of the Trust. The Manager is responsible for the day-to-day management of the business of the Trust subject to a supervisory role of the Board. In exercising its powers and discharging its duties under the Management Agreement, the Manager must exercise the degree of care, diligence and skill that a reasonably prudent advisor and manager in respect of petroleum and natural gas properties in western Canada would exercise in comparable circumstances.

Pursuant to the provisions of the Management Agreement, the Manager provides certain administrative and support services to the Trust, including those necessary to:

- Ensure compliance by the Trust with continuous disclosure obligations under applicable securities legislation.
- Provide investor relations services.
- Provide or cause to be provided to Unitholders all information to which Unitholders are entitled under the Trust Indenture.
- Call, hold and distribute materials including notices of meetings and information circulars in respect of all necessary meetings of Unitholders.
- Determine the amounts payable from time to time to Unitholders and to arrange for distributions to Unitholders.
- Determine the timing and terms of future offerings of Trust Units, if any.
- Determine the terms and conditions upon which the Trust may acquire additional royalties.
- Determine the terms and conditions upon which the Trust may from time to time borrow money.

Under the Management Agreement, the Manager receives a quarterly management fee paid in Trust Units. The Manager also earns an acquisition fee of 1.5% of the purchase price of oil and gas properties acquired. This fee is charged to capital assets as part of the properties acquired. The Management Agreement has a term of three years and will be automatically renewed on November 26, 2007, unless terminated.

OVERVIEW

Freehold Royalty Trust is structured as a mutual fund trust under the *Income Tax Act* (Canada). This enables us to return the majority of our income to Unitholders in a tax-effective manner. We receive revenue from oil and gas properties as reserves are produced, which is paid to Unitholders on a regular basis over the economic life of the properties.

We are one of the largest owners of royalty lands in western Canada. We have gross overriding royalty interests in approximately 1,260,300 acres, and our mineral title lands cover about 548,400 gross acres. In addition, we hold working interests in 197,241 gross (22,003 net) acres.

Royalties offer the benefit of sharing in production, without exposure to the capital costs, operating costs and environmental costs associated with oil and gas production. Our high percentage of royalty income results in superior netbacks, which maximizes distributions to Unitholders.

Our properties are geographically widespread throughout western Canada. We have interests in more than 22,000 wells and we receive royalty income from approximately 200 industry operators. Royalty rates vary from less than 1% (for some gross overriding royalties) to 22.5% (for lessor royalties). This diversity lowers our risk.

Our long reserve life, low sustaining capital investment requirements and the fact that so much development occurs on our lands at no cost to us make these assets very well suited to an energy trust.

Our primary goal is to extend cash distributions over the long term by actively managing our assets to sustain production and extend reserve life without diluting our Unitholders. Our strategy to achieve this is to:

- maintain an aggressive audit program;
- pursue development opportunities on our working interest properties;
- acquire appropriate assets with a bias toward royalty interests; and
- maintain a conservative approach to debt management.

BUSINESS RISKS AND MITIGATING STRATEGIES

The operations of an energy trust are subject to virtually the same industry risks and conditions faced by conventional oil and gas companies. The most significant of these include, but are not limited to:

- fluctuations in commodity prices and quality differentials as a result of weather patterns, world and North American market forces or shifts in the balance between supply and demand for crude oil and natural gas;
- variations in currency exchange rates;
- imprecision of reserve estimates and uncertainty of depletion and recoverability of reserves. Our reserves will deplete over time through continued production and we and our lessees may not be able to replace these reserves on an economic basis;
- industry activity levels and intense competition for land, goods and services and qualified personnel;
- stock market volatility and the ability to access sufficient capital from internal and external sources;
- operational or marketing risks resulting in delivery interruptions, delays or unanticipated production declines;
- changes in government regulations and taxation; and
- safety and environmental risks.

As a royalty trust, we are also subject to the following risks:

- as 15 royalty payors account for about two-thirds of our royalty income, changes to their businesses may have a significant effect on our results; and
- higher prime borrowing rates, which may increase interest expense on our debt, and which may make fixed income investments more attractive to investors of Trust Units.

We employ the following strategies to mitigate these risks:

- our diversified revenue stream limits the size of any one property with respect to our total assets;
- we are not liable for abandonment and reclamation costs on our royalty lands;
- due to our high percentage of royalty lands, we have one of the lowest all-in cost structures of our peer group. In addition, we maintain a focus on controlling direct costs to maximize profitability;
- we maintain an aggressive auditing program to ensure that royalties are paid on our production from our lands, that our royalties paid are in accordance with the prices obtained by the royalty payor and that unwarranted or excessive deductions are not being taken. During 2005, our audit staff issued audit exception queries amounting to $3.1 million, bringing the total amount of audit exception queries since 1997 to $16.3 million, $14.0 million of which has been recovered.
- we adhere to strict investment criteria for acquisitions, seeking royalty and working interest properties that have high netbacks, long reserve life, low risk development potential and product diversification;
- we market our products to a diverse range of buyers. Currently, we do not have any commodity price, exchange rate or interest rate hedging programs in place and do not anticipate a change in this policy;
- we employ a qualified team of oil and gas professionals with many years of experience and knowledge in managing our assets;
- we maintain levels of liability insurance that meet or exceed industry standards; and
- we employ a conservative approach to debt management. As circumstances warrant, we allocate a portion of funds generated from operations to debt repayment.

RESULTS OF OPERATIONS

2005 Highlights

- Acquired the Petrovera Resources Partnership on May 10, 2005, for $351.7 million.
- Production averaged 7,636 boe per day, up 37% from 2004.
- Price realizations averaged $48.53 per boe, up 28%.
- Operating netback averaged $45.49 per boe, up 34%.
- Funds generated from operations were $2.76 per Trust Unit, up 35%.
- Distributions to Unitholders totalled $1.92 per Trust Unit, up 11%.
- Net proved plus probable reserves increased 44% to 30.5 million boe.
- Reserve additions of 13.8 million boe during 2005 replaced annual production by 428%.
- A record 1,001 gross wells were drilling on our lands during 2005.

On May 10, 2005, we acquired Petrovera Resources, a general partnership, for $351.7 million, net of adjustments. The purchase price was funded with a combination of equity and debt. The acquisition was accounted for using the purchase method of accounting, with results of operations included from May 10, 2005. The largest acquisition in our history, Petrovera adds critical mass to enhance stability of our distributions over the long term, from royalty interest assets that are a very good fit with our existing portfolio. It doubles our royalty production and solidifies Freehold's position as the only oil and gas trust in Canada focused primarily on royalty interests. About 80% of our production now comes from royalty interests.

In 2005, Freehold achieved record revenue, funds generated from operations, and net income, fueled by a 37% boost to oil and gas production with the Petrovera acquisition, and a 28% increase in average price realizations. Our results are largely influenced by the price we receive for our oil and gas production. Our production remained unhedged, and we have no plans to enter into any foreign currency or commodity price hedges at this time. This policy is subject to quarterly review by our board of directors.

SELECTED ANNUAL DATA

($000s, except per unit data)	**2005**	2004	2003
Revenue, net of royalty expenses	**133,323**	75,514	69,969
Net income [1]	**58,346**	36,892	37,078
Per Trust Unit, basic and diluted *($)*	**1.36**	1.17	1.19
Total assets	**534,078**	208,001	211,872
Long-term debt	**107,000**	27,000	18,000
Distributions declared	**84,810**	54,490	53,149
Per Trust Unit *($)* [2]	**1.92**	1.73	1.70

1 2003 restated.
2 Based on the number of Trust Units issued and outstanding at each record date.

Distributions

Distributions in 2005 totalled a record $1.92 per Trust Unit. However, the Trust earned more taxable income in 2005 than the amounts distributed to Unitholders. As a result, all distributions paid in the year are 100% taxable. Our Trust Indenture requires that any taxable income earned in the Trust that exceeds the amount paid in distributions automatically becomes payable to Unitholders. Therefore, Unitholders of record on February 20, 2006 received an additional distribution of $0.08 per Trust Unit, as a result of the excess taxable income earned in 2005. This amount is included in the $1.92 mentioned above.

As of December 31, 2005, we have declared a total of $12.20 per Trust Unit in distributions since inception. The following analysis illustrates the advantage of our royalty lands. Royalty interest properties accounted for 78% of gross revenue and 90% of our distributions in 2005.

COMPONENTS OF 2005 DISTRIBUTIONS

($000s, except as noted)	Royalty Interest Properties	Working Interest Properties	Total Trust
Gross revenue	107,428	29,486	**136,914**
Royalty expense [1]	–	(3,591)	**(3,591)**
Net revenue	107,428	25,895	**133,323**
Operating expense	–	(6,530)	**(6,530)**
Net operating income	107,428	19,365	**126,793**
General and administrative expense	(3,382)	(1,010)	**(4,392)**
Interest expense	(2,755)	(403)	**(3,158)**
Income and capital taxes	–	(1,105)	**(1,105)**
Expenditures on reclamation	–	(104)	**(104)**
Funds generated from operations	101,291	16,743	**118,034**
Reclamation fund contributions	–	(318)	**(318)**
Development expenditures	–	(7,982)	**(7,982)**
Changes in debt	80,000	–	**80,000**
Proceeds from Trust Unit issuance	258,935	–	**258,935**
Acquisitions	(351,705)	–	**(351,705)**
Changes in working capital	(12,154)	–	**(12,154)**
Distributions declared	76,367	8,443	**84,810**
Percentage contribution	90%	10%	**100%**

1 Net of Alberta Royalty Credit.

The following reconciliation shows the deductions from funds generated from operations to arrive at distributions declared. In 2005, we distributed 72% of funds generated from operations.

PAYOUT RATIO [1]

($000s, except as noted)	**2005**	2004	2003
Funds generated from operations	$ **118,034**	$ 64,313	$ 60,658
Reclamation fund contributions	**(318)**	(357)	(283)
Development expenditures	**(7,982)**	(5,823)	(5,894)
Changes in debt	**80,000**	9,000	(1,499)
Proceeds from Trust Unit issuance	**258,935**	–	–
Acquisitions	**(351,705)**	(13,061)	(3,386)
Changes in working capital	**(12,154)**	418	3,553
Distributions declared	$ **84,810**	$ 54,490	$ 53,149
Payout ratio [1]	**72%**	85%	88%

1 Distributions declared as a percentage of funds generated from operations.

QUARTERLY REVIEW

The table below is a summary of our performance for the past eight quarters. This presentation illustrates the fluctuations in pricing experienced since the beginning of 2004, and the resultant effect on our quarterly financial results. As oil and gas prices are denominated in U.S. dollars, realized selling prices in Canadian dollars are influenced by currency exchange rates. In recent quarters, our results have benefited from strong commodity prices. In addition, the acquisition of Petrovera Resources on May 10, 2005 had a positive impact on our results. The Petrovera contribution is partially reflected in the second quarter (52 days of production) and fully reflected in the last two quarters of 2005.

QUARTERLY RESULTS

	2005				2004			
($000s, except as noted)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial								
Revenue, net of royalty expense	43,364	42,867	27,992	19,170	19,204	19,994	19,066	17,250
Funds generated from operations	38,694	38,893	24,344	16,103	16,139	17,392	16,407	14,375
Per Trust Unit *($)*	0.79	0.79	0.59	0.51	0.51	0.55	0.52	0.46
Distributions declared	31,366	22,527	17,981	12,936	15,449	14,808	12,593	11,640
Per Trust Unit *($)* [1]	0.64	0.46	0.41	0.41	0.49	0.47	0.40	0.37
Payout ratio *(%)*	81	58	74	80	96	85	77	81
Net income	18,747	19,373	10,858	9,368	9,397	10,306	9,515	7,674
Per Trust Unit, diluted *($)*	0.38	0.40	0.26	0.30	0.30	0.33	0.30	0.24
Long-term debt	107,000	118,000	120,000	27,000	27,000	17,000	17,000	18,000
Trust Units outstanding								
Weighted average *(000s)*	48,996	48,961	41,489	31,544	31,522	31,499	31,477	31,454
At quarter end *(000s)*	49,032	48,996	48,960	31,567	31,544	31,522	31,499	31,477
Operating								
Daily production *(boe/d)*	8,739	8,974	7,279	5,502	5,575	5,447	5,757	5,577
Average selling price *($/boe)*	54.95	52.61	42.42	39.47	38.37	40.96	37.37	35.00
Operating netback *($/boe)*	51.56	49.89	39.61	36.18	34.67	36.85	33.57	31.18
Benchmark Prices								
WTI crude oil *(US$/bbl)*	60.02	63.19	53.20	49.84	48.28	43.88	38.31	35.14
Exchange rate *(US$/Cdn$)*	0.85	0.83	0.80	0.82	0.82	0.77	0.74	0.76
Edmonton Par *(Cdn$)*	71.17	76.51	65.76	61.45	57.70	56.25	50.60	45.60
Light/heavy oil differential *($/bbl)*	28.14	20.79	24.17	22.48	21.60	14.29	13.29	10.67
Bow River/Hardisty *($/bbl)*	43.03	55.72	41.59	38.97	36.10	41.96	37.31	34.93
AECO natural gas *($/Mcf)*	11.68	8.17	7.38	6.69	7.08	6.66	6.80	6.61
Unit Trading Performance								
High *($)*	18.98	19.30	17.63	18.49	18.42	16.97	15.80	16.30
Low *($)*	15.15	15.99	14.25	15.50	15.75	14.57	14.65	14.02
Close *($)*	18.81	18.68	15.99	16.10	17.45	16.25	15.00	14.75
Volume *(000s)*	7,611	9,980	8,311	2,418	4,252	1,768	3,149	2,399

1 Based on the number of Trust Units issued and outstanding at each record date.

REVENUE

We receive revenue from approximately 200 industry operators. Gross revenue of $136.9 million in 2005 was 74% higher than in 2004. Higher production volumes, mainly from the Petrovera acquisition, accounted for roughly 63% of the revenue increase, with higher commodity prices accounting for the remainder. Petrovera's contribution was $44.8 million, 33% of our total gross revenue in 2005.

The accompanying table demonstrates the net effect of price and volume variances on gross revenue.

GROSS REVENUE VARIANCES

($000s)	**2005 vs. 2004**	2004 vs. 2003
Oil and NGL		
Production increase (decrease)	**16,191**	(1,637)
Price increase	**12,637**	7,896
Net increase	**28,828**	6,259
Natural gas		
Production increase (decrease)	**20,345**	(1,314)
Price increase	**8,531**	400
Net increase (decrease)	**28,876**	(914)
Other revenue increase (decrease)	**719**	(20)
Gross revenue increase	**58,423**	5,325

Production

Our production base is geographically widespread throughout western Canada, with the majority of properties located in Alberta. On a boe basis, 63% of our production is derived from oil and natural gas liquids, and 59% of this liquids production (37% of total boe production) is heavy oil. In 2005, production from working interest wells declined 7%, while royalty production rose 59%.

AVERAGE DAILY PRODUCTION BY PRODUCT TYPE

	2005	2004	2003
Light and medium oil *(bbls/d)*	**1,648**	1,580	1,586
Heavy oil *(bbls/d)*	**2,840**	2,014	2,102
NGL *(bbls/d)*	**345**	283	317
Total oil and NGL *(bbls/d)*	**4,833**	3,877	4,005
Natural gas *(Mcf/d)*	**16,821**	10,270	10,872
Oil equivalent *(boe/d)*	**7,636**	5,588	5,817
Total annual production *(Mboe)*	**2,787**	2,045	2,123
Potash *(tonnes/d)*	**9.7**	7.6	7.6

Petrovera began contributing approximately 3,800 boe per day of royalty production when the acquisition closed on May 10, 2005. Annualized over the full year, Petrovera's contribution was 2,465 boe per day. Petrovera production is almost entirely (99%) from royalty interests, which is an excellent strategic fit with Freehold's existing asset base. About 80% of our production now comes from royalty interests.

PRODUCTION RECONCILIATION

(boe/d)	Royalty Interest Properties	Working Interest Properties	**Total Trust**
2004 average daily production rate	3,711	1,877	**5,588**
2004 activities, full year impact	417	156	**573**
2005 development	245	180	**425**
2005 acquisitions	2,445	20	**2,465**
Natural decline	(933)	(482)	**(1,415)**
2005 average daily production rate	5,885	1,751	**7,636**

Product Prices

Commodity prices continued to demonstrate strength in 2005. WTI crude oil rose 37%. However, Bow River heavy oil increased only 19%, reflecting wider price differentials for heavy oil. In late 2004, we started to see a growing price differential, due to a surplus of heavy crude and a lack of upgrading capacity. In the fourth quarter of 2005, the average differential was $28.14 per barrel. Year-over-year, the Canadian dollar rose 7%, an important factor since oil is priced in U.S. dollars. The average AECO natural gas price was 25% higher in 2005.

AVERAGE BENCHMARK PRICES

	2005	2004	2003
WTI crude oil *(US$/bbl)*	**56.56**	41.40	31.04
Bow River Heavy oil *(Cdn$/bbl)*	**44.83**	37.60	32.68
Light/heavy oil differential *(Cdn$/bbl)*	**23.90**	14.94	10.46
AECO natural gas *(Cdn$/Mcf)*	**8.48**	6.79	6.70
Exchange rate *(US$/Cdn$)*	**0.8260**	0.7698	0.7158

In 2005, our average selling price was a record $48.53 per boe, up 28% from 2004. However, a 7% increase in the value of the Canadian dollar and widening in light/heavy oil price differentials resulted in a lower realized price for our oil production relative to the benchmark WTI price. The differential has a significant impact on our realizations, as approximately two-thirds of our oil production (37% of our total boe production) is heavy oil.

AVERAGE SELLING PRICES

	2005	2004	2003
Oil *($/bbl)*	**46.65**	38.08	32.77
NGLs *($/bbl)*	**50.58**	37.29	30.95
Oil and NGLs *($/bbl)*	**46.93**	38.03	32.63
Natural gas *($/Mcf)*	**8.55**	6.28	6.18
Oil equivalent *($/boe)*	**48.53**	37.91	34.01
Potash *($/tonne)*	**213.28**	167.37	133.36

Marketing and Hedging

Our royalty lands consist of a large number of royalty properties, with generally small volumes per property. A provision of the leases calls for our natural gas to be marketed with the lessees' production. Historically, we have chosen to market our oil production in the same manner, although some of our leases allow for us to take our oil production in-kind.

In order to speed up receipt of royalty income, we are taking steps to take our oil production in kind. As at December 31, 2005, approximately 34% of our royalty oil production was being marketed by Freehold using 30-day contracts. During 2006, we will continue pursue opportunities to take more of our royalty oil in-kind.

We market most of our working interest oil production using 30-day contracts to ensure the highest competitive pricing.

It has been our position to accept prices in the market and our production remains unhedged. This policy is subject to regular review by our board of directors.

EXPENSES

Royalty Expenses

Oil and gas producers pay royalties to the owners of mineral rights from whom they hold leases. These are paid to the Crown (provincial and federal government) and freehold mineral title owners. Royalty rates are directly related to sales prices and the level of oil and gas sales. In 2005, royalties paid on production relating to ownership in working interest properties totalled $3.6 million, or 3% of gross revenue.

ROYALTY EXPENSES

($000s, except as noted)	2005	2004	2003
Working interest properties	3,591	2,977	3,197
Per boe ($)	5.62	4.33	4.75
Royalty interest properties [1]	–	–	–
Per boe ($)	–	–	–
Total royalty expenses [1]	3,591	2,977	3,197
Total Trust [2] ($/boe)	1.29	1.46	1.51
As a percentage of gross revenue	3%	4%	4%

1 Net of Alberta Royalty Credit.
2 We do not incur royalty expenses on production from our royalty interest properties. As the royalty owner, we receive the royalty as income from other companies.

Operating Expenses

Operating expenses are comprised of direct costs incurred and costs allocated among oil, natural gas and natural gas liquids production. Operating recoveries associated with operated properties are excluded from operating costs and accounted for as a reduction to general and administrative costs. On our working interest properties, which account for 20% of our production, operating expenses rose 11% (20% per boe) in 2005. The increase stems largely from higher electricity and fuel costs in 2005, and prior period adjustments. With industry activity at record levels, the demand for oilfield goods and services is intense and the energy sector has been experiencing cost inflation. The majority of our working interest properties are operated by others. It is expected that cost reduction measures will be initiated to manage these increased costs.

As 80% of our production is from royalties, we are somewhat sheltered from the effects of increased costs because royalty production is not subject to these expenses. On a per boe basis, operating costs of our total operations (including the royalty lands) decreased 18% year over year, largely due to higher royalty production volumes in 2005.

OPERATING EXPENSES

($000s, except as noted)	2005	2004	2003
Working interest properties	6,530	5,860	5,190
Per boe ($)	10.22	8.53	7.71
Royalty interest properties [1]	–	–	–
Per boe ($)	–	–	–
Total operating expenses	6,530	5,860	5,190
Total Trust ($/boe) [1]	2.34	2.87	2.44
As a percentage of gross revenue	5%	7%	7%

1 We do not incur operating costs on our royalty interest properties.

General and Administrative Expenses

Our Manager is a wholly owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of Canadian National Railway Company). We reimburse the Manager for overhead expenses incurred on our behalf. During the year, the Manager charged us $3.0 million (2004 – $2.6 million) in general and administrative costs. At December 31, 2005, there was $219,000 (2004 – $393,000) included in accounts payable relating to these costs.

We have significant land administration, accounting and auditing requirements to administer and collect royalty payments. This includes systems to track lessee activity on the royalty lands. General and administrative expenses as a percentage of gross revenue have remained constant at 3%-4% for the past three years.

We experienced higher costs in 2005 as a result of increased staff levels and higher costs associated with regulatory compliance and financial reporting obligations. However, on a per boe basis, general and administrative expenses declined 8% year over year, as the Manager was able to administer the additional royalty production volumes with minimal staff additions. We also continued the work of evaluating internal controls. The anticipated cost of the project is expected to reach $500,000, of which $275,000 has been incurred to date.

GENERAL AND ADMINISTRATIVE EXPENSES

($000s, except as noted)	**2005**	2004	2003
Gross general and administrative expenses	**4,479**	3,610	2,987
Less overhead recoveries [1]	**(87)**	(108)	(121)
Net general and administrative expenses	**4,392**	3,502	2,866
Per boe *($)*	**1.58**	1.71	1.35
As a percentage of gross revenue	**3%**	4%	4%

1 As we do not operate any of our royalty production, our overhead recoveries are minimal.

Netback

Netback, calculated on a boe basis, represents the cash margin on the sale of oil and gas. Operating netback is calculated by subtracting royalty expenses and operating costs from revenues. On the majority of our production, we receive royalty income from gross production revenue – before deduction of third-party royalty expenses and operating costs. We do not incur development expenditures, operating expenses, abandonment or site restoration expenses on our royalty production. The accompanying netback analysis demonstrates the positive effect of this royalty advantage.

OPERATING NETBACK

($ per boe)	**2005**	2004	2003
Royalty interest properties	**50.01**	38.78	34.42
Working interest properties	**30.30**	24.71	22.08
Total Trust	**45.49**	34.05	30.51

2005 NETBACK ANALYSIS

($ per boe)	Royalty Interest Properties	Working Interest Properties	**Total Trust**
Gross revenue [1]	50.01	46.14	**49.12**
Royalty expense [2]	–	(5.62)	**(1.29)**
Net revenue	50.01	40.52	**47.83**
Operating expense	–	(10.22)	**(2.34)**
Operating netback	50.01	30.30	**45.49**
General and administrative expense	(1.58)	(1.58)	**(1.58)**
Interest expense	(1.28)	(0.63)	**(1.13)**
Income and capital taxes	–	(1.73)	**(0.39)**
Expenditures on reclamation	–	(0.16)	**(0.04)**
Funds generated from operations	47.15	26.20	**42.35**
Reclamation fund contributions	–	(0.50)	**(0.11)**
Development expenditures	–	(12.49)	**(2.86)**
Changes in debt	37.24	–	**28.70**
Proceeds from Trust Unit issuance	120.54	–	**92.90**
Net acquisition cost	(163.73)	–	**(126.19)**
Changes in working capital	(5.66)	–	**(4.36)**
Investor netback [3]	35.54	13.21	**30.43**

1 Includes potash revenue, sulphur revenue and other.
2 Net of Alberta Royalty Credit.
3 Excludes management fee paid in Trust Units.

OPERATING NETBACK BY PRODUCT TYPE

	2005	2004	2003
Light and medium oil *($/bbl)*	**56.02**	41.17	34.87
Heavy oil *($/bbl)*	**34.31**	26.87	23.51
Natural gas *($/Mcf)*	**8.13**	5.75	5.62
NGL *($/bbl)*	**47.14**	33.55	27.66
Combined *($/boe)* [1]	**45.49**	34.05	30.51

1 Includes potash revenue, sulphur revenue and other.

Management Fees

The Manager of the Trust receives its management fee in Trust Units. The issue of 17.4 million Trust Units in May resulted in a pro-rata increase in the management fee, in accordance with the management contract. The management fee for 2005 was 123,825 Trust Units (2004 – 90,000 Trust Units). The ascribed value is based on the closing price of the Trust Units at the end of each quarter. The change in the ascribed value of management fees reflects the higher market price of our Trust Units during 2005, and the increase in Trust Units issued to the Manager. The management fee is currently 35,654 Trust Units per quarter.

The Manager also received a fee of $5.3 million relating to acquisitions completed during 2005. Since inception in late 1996, the Manager has received total fees of $15.7 million, representing 3% of gross revenue for the period.

MANAGEMENT FEES

($000s, except as noted)	**2005**	2004	2003
Management fees (paid in Trust Units) [1]	**2,178**	1,428	1,235
Acquisition fees (1.5%)	**5,306**	197	52
Total fees	**7,484**	1,625	1,287
Per boe *($)*	**2.69**	0.79	0.61
As a percentage of gross revenue	**5%**	2%	2%
As a percentage of distributions	**9%**	3%	2%

1 The ascribed value of the management fees is based on the closing Trust Unit price at the end of each quarter.

Interest Expense

Additional debt assumed in May 2005 to acquire Petrovera Resources resulted in increased interest expense.

INTEREST EXPENSE

($000s, except per boe)	**2005**	2004	2003
Interest on operating line	**13**	7	2
Interest on long-term debt	**3,145**	628	776
Net interest expense	**3,158**	635	778
Per boe *($)*	**1.13**	0.31	0.37
As a percentage of gross revenue	**2%**	1%	1%

Depletion and Ceiling Test

Oil and gas properties and royalty interests, including the cost of production equipment and future capital costs associated with proven reserves and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties payable (see Accounting Policies and Critical Estimates).

During 2005, the provision for depletion and depreciation was $56.9 million ($20.43 per boe), compared with $25.7 million ($12.55 per boe) in 2004. Reserves are independently evaluated on an annual basis. For the first three quarters of 2005, the estimate of proved reserves was based on the independent evaluation dated December 31, 2004, adjusted for acquisitions and production. The fourth quarter results were adjusted to reflect the annual reserve evaluation as at December 31, 2005.

Our ceiling test calculation, performed at December 31, 2005, resulted in no impairment loss. The future prices used in estimating cash flows were based on forecasts by an independent reserves evaluator, adjusted for our quality, transportation, and contract differences.

Reclamation Fund

We are liable for ongoing environmental obligations and for the ultimate reclamation of the working interest properties upon abandonment. No similar responsibilities arise from the royalty lands. Ongoing environmental obligations are funded from funds generated from operations. At December 31, 2005, our estimated undiscounted share of future environmental and reclamation obligations for the working interest properties is approximately $10.3 million.

A reclamation fund was established when the Trust was formed. The fund consists of cash invested in an interest-bearing account and is funded by quarterly cash payments. In 2005, contributions to the reclamation fund totalled $422,000, including interest. For 2006, quarterly contributions will remain at $100,000 to ensure that future obligations can be met.

RECLAMATION FUND SUMMARY

($000s)	Cumulative Since Inception	**2005**	2004	2003
Reclamation fund, beginning balance	–	**1,646**	1,289	1,006
Reclamation fund contributions	2,527	**422**	414	317
Expenditures on reclamation	(563)	**(104)**	(57)	(34)
Reclamation fund, ending balance	1,964	**1,964**	1,646	1,289

Taxes

Freehold Royalty Trust is a taxable trust under the *Income Tax Act* (Canada). We distribute substantially all of our taxable income to you as a Unitholder. By doing so, exposure to current tax at the trust level is eliminated. In addition, we are exempt from future income taxes because we are contractually committed to distribute all of our income to Unitholders.

Capital taxes consist primarily of the Saskatchewan Capital Tax applied to both taxable capital and gross revenues in that province. Our subsidiary, Freehold Resources Ltd., is a Canadian corporation subject to tax in various jurisdictions. Freehold Resources Ltd. can deduct royalty payments to us in determining its taxable income, and is generally liable for income taxes on its 1% residual interest. Freehold Resources Ltd. is subject to federal and capital tax in any jurisdiction (federal and provincial) in which it has a permanent establishment. In 2005, Freehold Resources Ltd. had taxable income that gave rise to current income taxes of $1.0 million (2004 – $1.0 million).

TAXES

($000s)	**2005**	2004	2003
Large Corporations Tax	**–**	–	23
Provincial Capital Tax	**120**	116	80
Current income tax	**985**	1,031	340
Total	**1,105**	1,147	443

TAX POOLS

($000s)	2005	2004	2003
Canadian oil and gas property expense	144,295	160,338	166,767
Canadian development expense	8,052	5,971	6,710
Canadian exploration expense	–	–	–
Capital cost allowance	7,516	6,571	5,763
Unit issue costs	8,855	269	537
Non-capital loss carryovers	–	–	–
Total [1]	168,718	173,149	179,777

1 These amounts represent our direct tax pools as well as the tax pools of our subsidiary, Freehold Resources Ltd.

Unitholder Taxation

We are entitled to claim certain tax deductions available to all owners of oil and gas properties. By using two principal deductions – the Canadian Oil and Gas Property Expense and the Resource Allowance – cash distributions in the Trust's initial years were sheltered from income tax. Over time, as a result of a general reduction in tax pools available for future claims, an increasing percentage of the annual distributions become taxable.

A total of $2.04 per Trust Unit was distributed with respect to 2005. For Canadian tax purposes, 100% of these distributions were taxable to Unitholders. For 2006, we currently estimate that, for residents of Canada, 100% of distributions to Unitholders will be taxable as other income.

Distributions with respect to 2005 operations totalled $1.92 per Trust Unit. However for tax filing purposes, Unitholders should report total distributions declared of $2.04 per Trust Unit. The difference of $0.12 per Trust Unit is attributable to the monthly distribution declared in December 2004 and paid on January 15, 2005. Effectively, the 2005 tax slips include distributions for 13 months of operations.

On September 8, 2005, the Government of Canada's Department of Finance issued a consultation paper entitled Tax and Other Issues Related to Publicly Listed Flow-Through Entities (Income Trusts and Limited Partnerships). On November 23, 2005, the Finance Department ended the consultation process, announcing no changes to the tax treatment of income trusts and flow-through entities. Instead, it announced a reduction in personal income taxes on dividends. The decision levels the playing field between corporations and trusts by establishing a better balance between the tax treatment of these entities.

LIQUIDITY AND CAPITAL RESOURCES

In conjunction with the Petrovera acquisition, we expanded our credit facilities from $65 million to $165 million. These credit facilities were used to fund $93 million of the purchase price for the acquisition, inclusive of transaction costs.

At December 31, 2005, we had no short-term debt outstanding and long-term debt was $107 million. We had working capital of $16.3 million, resulting in net debt of $90.7 million.

DEBT ANALYSIS

($000s)	2005	2004	2003
Long-term debt	107,000	27,000	18,000
Short-term debt (operating line)	–	–	–
Less: working capital	16,281	4,128	4,367
Net debt obligations	90,719	22,872	13,633

At December 31, 2005, our ratio of net debt (long-term debt less positive working capital) to trailing funds generated from operations was 0.8 to 1, compared with 0.4 to 1 at the end of 2004.

FINANCIAL LEVERAGE AND COVERAGE RATIOS [1]

	2005	2004	2003
Net debt to trailing funds generated from operations *(times)*	0.8	0.4	0.2
Distributions to interest expense *(times)*	26.9	86.0	68.0
Net debt to distributions *(times)*	1.1	0.4	0.3
Net debt to net debt plus equity *(%)*	18.5	12.2	7.0

1 Funds generated from operations, distributions, and interest expense are 12-months trailing.

Sources and Uses of Funds

The following table outlines our sources and uses of funds during the past three years.

SOURCES AND USES OF FUNDS

($000s)	2005	2004	2003
Sources of funds			
Funds generated from operations	118,034	64,313	60,658
Equity issued, net of costs	258,935	–	10,501
Change in non-cash working capital	20,990	(212)	3,169
	355,979	64,101	74,328
Uses of funds			
Debt reduction (addition)	(80,000)	(9,000)	12,000
Net reclamation fund contributions	318	357	283
Development expenditures	7,982	5,823	5,894
Property acquisitions, net of costs	351,705	13,061	3,386
Distributions declared	75,848	53,851	53,024
Change in cash	126	9	(259)
	355,979	64,101	74,328

The increased royalty interest production from the Petrovera acquisition has required a significant, one-time increase in our receivables, caused by the normal lag in receiving royalty revenue. The dollar amount of receivables also increased due to higher commodity prices. In addition, on December 31, distributions payable to Unitholders included the special distribution of $0.08 per Trust Unit as a result of excess taxable income earned in 2005. These increases resulted in a change to working capital of $12.2 million during 2005.

The following table illustrates the changes in working capital at the end of each quarter during 2005.

COMPONENTS OF WORKING CAPITAL

($000s)	December 31 2005	September 30 2005	June 30 2005	March 31 2005	December 31 2004
Cash	192	17	215	146	66
Accounts receivable	35,728	35,211	21,707	13,642	12,797
Current assets	35,920	35,228	21,922	13,788	12,863
Distributions payable to Unitholders	12,748	6,859	5,875	3,788	3,785
Accounts payable and accrued liabilities	6,891	6,713	4,593	3,829	4,950
Current liabilities	19,639	13,572	10,468	7,617	8,735
Working capital [1]	16,281	21,656	11,454	6,171	4,128

1 Working capital is comprised of current assets minus current liabilities.

Acquisitions and Development Expenditures

We completed acquisitions for $352 million (net of adjustments) in 2005. These acquisitions will contribute approximately 3,700 boe per day to our royalty production base in 2006.

We continue to pursue opportunities to augment our production and reserves, primarily targeting royalty interests, while maintaining a disciplined valuation approach to ensure that any acquisition we complete will be accretive to our present and future Unitholders.

ACQUISITION SUMMARY

($000s)	2005	2004	2003
Purchase price	353,713	13,125	3,512
Acquisition fee (1.5%)	5,306	197	53
Interest expense	5,349	–	12
Evaluation and legal costs	2,303	30	–
Purchase price adjustments [1]	(14,966)	(471)	(191)
Additions to petroleum and natural gas interests	351,705	12,881	3,386
Working capital	–	180	–
Net acquisition costs	351,705	13,061	3,386

1 Net revenue from effective date to closing.

Our development expenditure obligations are deducted from funds generated from operations prior to the determination of distributions to Unitholders. The amount of expenditures to be deducted is limited to 15% of annual funds generated from operations. As we do not incur development expenditures on our royalty lands, our capital requirements are modest, relative to most energy trusts. In 2005, development expenditures of $8 million amounted to 7% of funds generated from operations.

For 2006, we have approved a capital budget of $6 million. At Hayter, we expect to spend $3.5 million to tie-in new production from the 2005 drilling program, expand water handling facilities, and drill 11 (2.6 net) infill locations. The remaining capital will be spent on development activities in Southeast Saskatchewan and on miscellaneous properties. We

anticipate that development activities on working interest properties in 2006 will add approximately 190 boe per day of production.

DEVELOPMENT EXPENDITURES

($000s)	**2005**	2004	2003
Development drilling	**5,379**	3,451	4,605
Plant and facilities	**2,603**	2,372	1,289
Total development expenditures	**7,982**	5,823	5,894

Trust Units Outstanding

As at March 14, 2006, there were 49,031,581 Trust Units outstanding, unchanged from the number of Trust Units outstanding as at December 31, 2005. There are no options outstanding under the Trust Unit option plan.

TRUST UNITS OUTSTANDING

	2005	2004	2003
Weighted average	**42,812,470**	31,488,355	31,164,161
At December 31	**49,031,581**	31,544,236	31,454,236

INDUSTRY TRENDS

We view continuing development on our royalty lands as an essential part of our future success. To date, we have seen no evidence to suggest that this activity is slowing. Although the Western Canadian Sedimentary Basin is maturing, drilling activity continues at a record pace. The industry as a whole drilled 24,800 wells in 2005, just shy of the record 25,000 wells drilled in 2004. The Petroleum Services Association of Canada (PSAC) predicts that more than 25,000 wells will be drilled in Western Canada in 2006. As activity on our royalty lands generally mirrors industry activity, we expect that drilling on our royalty lands will likewise remain at high levels.

Crude oil markets continue to be strong. Demand remains robust, especially from China, and the outlook for 2006 is positive. Although natural gas prices tend to be more volatile than oil prices due to supply and demand factors within North America, the outlook for natural gas prices is also positive. However, the higher Canadian currency will offset a portion of the economic benefit of higher commodity prices.

Of great concern to us is the growing surplus of heavy crude and lack of upgrading capacity, which may have a significant negative impact on our price realizations due to our heavier product mix. The price differential between light and heavy crude oil depends on the relative supply and demand fundamentals of each commodity and, at times, is quite significant. Within North America, only certain refineries are configured to process heavy oil and their processing capacity is limited. In addition, bitumen production from Alberta's oil sands is expected to increase significantly over the next several years. As a result, markets for heavy oil and bitumen will be somewhat uncertain in the future. Supply and demand imbalances could result in the heavy oil price differential remaining well above historical averages.

DISTRIBUTION OUTLOOK

We enter 2006 with strong production volumes, with contribution from the Petrovera acquisition for the full year. Based on the assumptions in the accompanying table, we estimate that distributions in 2006 will total $2.16 per Trust Unit. This estimate does not include quarterly top-ups. Our guidance will be updated quarterly throughout the year. Recognizing the cyclical nature of our industry, we caution that significant changes (positive or negative) in commodity prices (including light/heavy oil price differentials), foreign exchange rates or production rates will result in adjustments to the distribution level. It is also inherently difficult to predict activity levels on our royalty lands since we do not know the future plans of the various operators.

The regular monthly cash distribution is set at $0.18 per Trust Unit. In keeping with our stated practice, a portion of any excess income available for distribution may be directed toward repayment of long-term debt and working capital improvement where the board of directors considers it appropriate or necessary.

2006 DISTRIBUTION OUTLOOK AS AT FEBRUARY 22, 2006

Estimated cash distributions *($/Trust Unit)*	**2.16**
Assumptions	
Average daily production, excluding acquisitions *(boe/d)*	**8,500**
Average WTI oil price *(US$/bbl)*	**60.75**
Average AECO natural gas price *(Cdn$/Mcf)*	**8.80**
Average light/heavy oil price differential *(Cdn$/bbl)*	**30.00**
Average exchange rate *(US$/Cdn$)*	**0.86**
Average operating costs *($/boe)*	**2.25**
Average general and administrative costs *($/boe)*	**1.65**
Capital expenditures *($ millions)*	**6.0**
Long-term debt at year end *($ millions)*	**100**
Weighted average Trust Units outstanding *(000s)*	**49,100**
Payout ratio *(%)*	**89**
Estimated taxability of distributions, as other income *(%)*	**100**

The following table provides an analysis of the potential impact key factors may have on distributions to Unitholders, based on our 2006 budget forecast.

SENSITIVITY ANALYSIS

Variables	Change (+/–)	Estimated Change in Distributions to Unitholders	
		($000s)	*($/Trust Unit)*
WTI crude oil price	US$1.00/bbl	**2,249**	**0.05**
Light/heavy oil price differential	Cdn$1.00/bbl	**1,940**	**0.04**
Natural gas price	Cdn$0.25/Mcf	**1,756**	**0.04**
Exchange rate *(US$/Cdn$)*	0.01	**1,319**	**0.03**
Interest rates	1%	**1,040**	**0.02**
Oil and NGL production	100 bbls/d	**1,461**	**0.03**
Natural gas production	1,000 Mcf/d	**3,143**	**0.06**

+ MANAGEMENT'S REPORT

Management has prepared the accompanying consolidated financial statements of Freehold Royalty Trust in accordance with Canadian generally accepted accounting principles.

Management is responsible for the accuracy and integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded, transactions are properly authorized and reliable accounting records are produced for financial reporting purposes.

External auditors, KPMG LLP, were appointed by the Unitholders to perform an examination of the corporate and accounting records so as to express an opinion on the consolidated financial statements of Freehold Royalty Trust. Their examination included tests and procedures considered necessary to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The board of directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. It exercises its responsibilities primarily through the audit committee, all of whose members are independent directors of Freehold Resources Ltd. The committee meets with management and the independent auditors to ensure that management's responsibilities are properly discharged.

David J. Sandmeyer
PRESIDENT AND CHIEF EXECUTIVE OFFICER

Joseph N. Holowisky
VICE PRESIDENT, FINANCE AND ADMINISTRATION,
CHIEF FINANCIAL OFFICER AND SECRETARY

FEBRUARY 22, 2006

To the Unitholders of Freehold Royalty Trust

We have audited the consolidated balance sheets of Freehold Royalty Trust as at December 31, 2005 and 2004, and the consolidated statements of income and deficit and cash flows for the years then ended. These consolidated financial statements are the responsibility of Freehold's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Freehold as at December 31, 2005 and 2004, and the results of its operations and its cash flows for the years then ended, in accordance with Canadian generally accepted accounting principles.

KPMG LLP

KMPG LLP
Chartered Accountants
Calgary, Canada

February 22, 2006

+ CONSOLIDATED BALANCE SHEETS

	December 31	
($000s)	**2005**	2004
Assets		
Current assets:		
Cash	**$ 192**	$ 66
Accounts receivable	**35,728**	12,797
	35,920	12,863
Reclamation fund (note 5)	**1,964**	1,646
Petroleum and natural gas interests (note 2)	**496,194**	193,492
	$ 534,078	$ 208,001
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	**$ 12,748**	$ 3,785
Accounts payable and accrued liabilities	**6,891**	4,950
	19,639	8,735
Asset retirement obligation (note 5)	**4,036**	3,937
Long-term debt (note 4)	**107,000**	27,000
Future income tax liability (note 9)	**3,932**	3,507
Unitholders' equity:		
Unitholders' capital (note 6)	**560,049**	298,936
Deficit	**(160,578)**	(134,114)
	399,471	164,822
	$ 534,078	$ 208,001

See subsequent event in note 8.
See accompanying notes to consolidated financial statements.

Approved on behalf of Freehold Royalty Trust by Freehold Resources Ltd., as Administrator:

W. Siebens

William W. Siebens
DIRECTOR

D. Nolan Blades
DIRECTOR

CONSOLIDATED STATEMENTS OF INCOME AND DEFICIT

	Years Ended December 31	
($000s, except per unit and weighted average data)	**2005**	2004
Revenue:		
Royalty income and working interest sales	**$ 136,914**	$ 78,491
Royalty expense (net of Alberta Royalty Credit)	**(3,591)**	(2,977)
	133,323	75,514
Other expenses:		
Operating	**6,530**	5,860
General and administrative	**4,392**	3,502
Interest on long-term debt	**3,158**	635
Depletion and depreciation	**56,938**	25,661
Accretion of asset retirement obligation (note 5)	**252**	232
Management fee (note 7)	**2,178**	1,428
	73,448	37,318
Net income before taxes	**59,875**	38,196
Income and capital taxes (note 9)	**1,105**	1,147
Future income tax provision (note 9)	**424**	157
	1,529	1,304
Net income	**58,346**	36,892
Deficit, beginning of year	**(134,114)**	(116,516)
Distributions declared	**(84, 810)**	(54,490)
Deficit, end of year	**$ (160,578)**	$ (134,114)
Net income per Trust Unit, basic and diluted	**$ 1.36**	$ 1.17
Weighted average number of Trust Units	**42,812,470**	31,488,355

See accompanying notes to consolidated financial statements.

+ CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31	
($000s)	**2005**	2004
Cash provided by (used in):		
Operating:		
Net income	**$ 58,346**	$ 36,892
Items not involving cash:		
Depletion and depreciation	**56,938**	25,661
Future income tax provision	**424**	157
Accretion of asset retirement obligation	**252**	232
Trust Units issued in lieu of management fee	**2,178**	1,428
Expenditures on reclamation	**(104)**	(57)
Funds generated from operations	**118,034**	64,313
Changes in non-cash working capital (note 10)	**(20,967)**	(262)
	97,067	64,051
Financing:		
Issue of Trust Units, net of issue costs	**258,935**	–
Long-term debt	**80,000**	9,000
Distributions paid	**(75,848)**	(53,851)
Changes in non-cash working capital (note 10)	**(142)**	(8)
	262,945	(44,859)
Investing:		
Corporate acquisition	**–**	(3,048)
Property and royalty acquisitions (note 3)	**(351,705)**	(10,013)
Development expenditures	**(7,982)**	(5,823)
Increase in reclamation fund	**(318)**	(357)
Changes in non-cash working capital (note 10)	**119**	58
	(359,886)	(19,183)
Increase in cash	**126**	9
Cash, beginning of year	**66**	57
Cash, end of year	**$ 192**	$ 66

See accompanying notes to consolidated financial statements.

Years ended December 31, 2005 and 2004.

BASIS OF PRESENTATION

Freehold Royalty Trust (the Trust) is an open-end investment trust formed under the laws of the Province of Alberta pursuant to a Trust Indenture dated September 30, 1996 as amended from time to time. The Trust holds royalty interests directly and a 99% royalty interest in the funds generated by its wholly owned subsidiary, Freehold Resources Ltd. (Freehold Resources). Freehold Resources was incorporated on June 3, 1996 and derives its income from certain petroleum and natural gas working interest properties. The Trust also holds royalty interests and working interests through Petrovera Resources (Petrovera), a general partnership acquired on May 10, 2005.

These consolidated financial statements include the accounts of the Trust, Freehold Resources and Petrovera. All inter-entity transactions have been eliminated.

1. SIGNIFICANT ACCOUNTING POLICIES

(a) Petroleum and Natural Gas Interests:

The Trust follows the full cost method of accounting.

All costs of acquiring, exploring for and developing oil and gas and related reserves are capitalized. Such costs include land acquisition, geological and geophysical, carrying charges of unproved properties, costs of drilling both productive and non-productive wells, directly related general and administrative costs and asset retirement costs. Costs are reduced by proceeds from the sale of oil and gas properties and by government grants. Gains and losses are not recognized upon disposition of oil and gas properties unless such a disposition would alter the rate of depletion by 20% or more.

(b) Ceiling Test:

Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties.

The carrying amount is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved interests and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

(c) Depletion:

Oil and gas interests and royalty interests, including the costs of production equipment, future capital costs associated with proved reserves and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. Reserves are converted to equivalent units on the basis of relative energy content.

(d) Asset Retirement Obligations:

The Trust recognizes the fair value of an asset retirement obligation in the period in which it is incurred and when a reasonable estimate of the fair value can be made. The fair value of the estimated asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on a unit-of-production method over the life of the reserves. In periods subsequent to initial measurement, the passage of time results in liability changes and the amount of accretion is charged against current period income. The liability is also adjusted for revisions to previously used estimates.

(e) Income and Other Taxes:

The Trust is a taxable trust under the *Income Tax Act* (Canada) and it distributes substantially all of its taxable income to its Unitholders. The tax deductions received by the Trust for the distributions to Unitholders represent an exemption from taxation equivalent to the Trust's earnings. In addition, the Trust is exempt from future income taxes because it is contractually committed to distribute all of its income to its Unitholders.

Freehold Resources follows the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. Freehold Resources can deduct royalty payments to the Trust in determining taxable income and is generally liable for income taxes on its 1% residual interest.

(f) Cash:

Cash includes cash on deposit and highly liquid investments with original maturities of three months or less.

(g) Measurement Uncertainty:

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses during the reporting period. Actual results could differ as a result of using estimates.

(h) Unit Based Compensation Plans:

In accordance with the Trust's Unit Option Plan, Trust Units are granted to the independent directors of Freehold Resources and to the Manager, Rife Resources Management Ltd.

The Trust accounts for its Unit Option Plan using the fair value method. Under this method, the Trust records a compensation expense over the vesting period of the plan, with a corresponding increase to contributed surplus. Upon exercise of the options, consideration paid, together with the amount previously recognized in contributed surplus, is recorded as an increase in Unitholders' capital.

(i) Earnings Per Unit:

Basic units outstanding are the weighted average number of units outstanding for each period. Diluted units outstanding are calculated using the treasury stock method, which assumes that any proceeds received from options with a market value in excess of option price would be used to buy back units at the average market price for the period.

(j) Revenue Recognition:

Revenue from the sale of crude oil, natural gas and natural gas liquids is recognized when title passes from the Trust, or the operator of the Trust's royalty properties, to its customers.

2. PETROLEUM AND NATURAL GAS INTERESTS

($000s)		**2005**		2004
Petroleum and natural gas interests	$	**734,051**	$	374,411
Accumulated depletion and depreciation		**(237,857)**		(180,919)
Petroleum and natural gas interests, net	$	**496,194**	$	193,492

The depletion calculation included $2.6 million (2004 - $1.6 million) for estimated future development costs associated with proved undeveloped reserves and excluded $14.1 million (2004 – $2.7 million) for the lower of cost and estimated value of unproved lands.

The Trust's ceiling test calculation, performed at December 31, 2005, resulted in no impairment loss. The future prices used by the Trust in estimating cash flows were based on forecasts by an independent reserves evaluator, adjusted for the Trust's quality, transportation, and contract differences. The following table summarizes the benchmark prices used in the calculation.

Year	WTI Oil *(US$/bbl)*	Foreign Exchange Rate	Edmonton Par Crude Oil *(Cdn$/bbl)*	AECO Gas *(Cdn$/MMBtu)*
2006	60.81	0.85	70.07	11.58
2007	61.61	0.85	70.99	10.84
2008	54.60	0.85	62.73	8.95
2009	50.19	0.85	57.53	7.87
2010	47.76	0.85	54.65	7.57
Average annual increase, thereafter	1.5%	–	1.5%	1.5%

3. BUSINESS COMBINATIONS

On May 10, 2005 the Trust closed the acquisition of Petrovera Resources, a general partnership which owns certain royalty, mineral title and working interests. The acquisition cost of $351.7 million (net of adjustments) was funded partially with a concurrent equity financing consisting of 13.5 million Trust Units at $15.55 per Trust Unit and a private placement to the vendor of 3.9 million Trust Units at $15.55 per Trust Unit for net proceeds of $258.9 million. The remaining cost of $92.8 million was financed utilizing the Trust's credit facilities. The acquisition was accounted for using the purchase method of accounting with the results of operations being included from May 10, 2005.

The fair values of the acquisition costs are allocated as follows:

($000s)		
Petroleum and natural gas interests	$	351,705
Asset retirement obligations		(19)

The above purchase price equation has not been finalized and is subject to certain revenue adjustments.

On July 31, 2004, the Trust acquired all of the issued and outstanding shares of Ventana Ventures Inc., a private corporation, for cash. Ventana was the owner of producing royalty income properties in the Peace River area of Alberta. Results of operations for the acquisition have been included in the Trust's financial results for the period from August 1, 2004 onward.

The transaction was accounted for by the purchase method with fair values as follows:

($000s)		
Net assets acquired:		
Petroleum and natural gas interests	$	2,868
Working capital		180
	$	3,048

4. LONG-TERM DEBT

The Trust has a $150 million extendible revolving term credit facility, extendible annually, on which $107 million was drawn at December 31, 2005. In the event that the lender does not consent to an extension, the revolving credit facility will revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period. In addition Freehold has available a $15 million extendible revolving operating facility, undrawn at December 31, 2005. The facilities are up for renewal in May 2006.

Borrowings under the facilities bear interest at the Bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 85 to 140 basis points and standby fees.

The facilities are secured with $300 million demand debentures over Freehold's petroleum and natural gas assets.

5. ASSET RETIREMENT OBLIGATIONS

The Trust has no asset retirement obligations on its royalty interest properties. The Trust's asset retirement obligation results from its responsibility to abandon and reclaim its net share of all working interest properties. The net present value of the Trust's total asset retirement obligation is estimated to be $4 million (discounted at a weighted average credit adjusted risk free rate of 6.2%), with the undiscounted value being $10.3 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being more than 15 years away.

	December 31			
($000s)		**2005**		2004
Balance, beginning of year	**$**	**3,937**	$	3,606
Liabilities incurred		**210**		156
Liabilities added upon acquisition		**19**		–
Liabilities settled		**(104)**		(57)
Liabilities disposed		**(352)**		–
Revision in estimates [1]		**74**		–
Accretion expense		**252**		232
Balance, end of year	**$**	**4,036**	$	3,937

1 Revision in estimates is mainly a result of changes in estimates provided by the Trust's independent reserves evaluator.

A reclamation fund, consisting of cash invested in an interest-bearing account, has been established and is funded by quarterly cash payments. All liabilities settled during the periods are paid from the reclamation fund.

6. UNITHOLDERS' CAPITAL

The Trust has authorized an unlimited number of Trust Units of which 49,031,581 were issued at December 31, 2005 (2004 – 31,544,236).

TRUST UNITS ISSUED

	2005		2004	
	Number	Amount ($000s)	Number	Amount ($000s)
Balance, beginning of year	31,544,236	$ 298,936	31,454,236	$ 297,508
Issued for cash	17,363,520	270,003	–	–
Less: Issue costs	–	(11,068)	–	–
Issued in lieu of management fee	123,825	2,178	90,000	1,428
Balance, end of year	49,031,581	$ 560,049	31,544,236	$ 298,936

The Trust has reserved 820,000 Trust Units pursuant to a Trust Unit Option Plan. Options to purchase Trust Units may be issued to the independent directors of Freehold Resources or to the Manager. As at December 31, 2005 and 2004, no options to purchase Trust Units were outstanding.

The Trust has reserved 500,000 Trust Units pursuant to its Management Agreement with the Manager, of which 388,061 have been issued to date.

7. RELATED PARTY TRANSACTIONS

The Manager provides certain services for a fee based on a specified number of Trust Units per quarter, pursuant to a Management Agreement which has a term of three years and will be renewed on November 26, 2007 unless terminated. During 2005, the management fee charged was 123,825 Trust Units with an ascribed value of $2.2 million (2004 – 90,000 Trust Units with an ascribed value of $1.4 million).

During the year, the Manager charged the Trust $3.0 million (2004 – $2.6 million) in general and administrative costs. At December 31, 2005, there was $219,000 (2004 – $393,000) included in accounts payable relating to these costs.

The Manager also earns a fee of 1.5% of the purchase price of oil and gas properties acquired by the Trust. During 2005, the Manager acquired $353.7 million (gross purchase price) of properties on behalf of the Trust (2004 – $13.1 million) and was paid $5.3 million (2004 – $197,000). This fee was charged to petroleum and natural gas interests as part of the properties acquired.

8. DISTRIBUTIONS TO UNITHOLDERS

Regular distributions to Unitholders are declared on a monthly basis, with payments to be made on the 15th day following the month end.

As a result of excess taxable income earned in 2005, the Trust declared an additional distribution of $0.08 per Trust Unit on February 9, 2006. This amount is reflected as a current liability in distributions payable to Unitholders as at December 31, 2005, along with the regular monthly distribution of $0.18 per Trust Unit.

9. INCOME TAXES

Freehold Resources uses the asset and liability method of accounting for income taxes, as described in note 1. The provision for income taxes in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial tax rate to the Trust's earnings before income taxes. This difference results from the following items:

($000s)		2005		2004
Earnings before income taxes and capital taxes	$	59,875	$	38,196
Combined federal and provincial tax rate		38.0%		39.2%
Computed expected income tax expense	$	22,723	$	14,983
Increase (decrease) in income tax resulting from:				
Non-taxable earnings of the Trust		(21,009)		(13,528)
Non-deductible Crown charges		254		204
Resource allowance		(505)		(491)
Benefit of future rate reductions		(56)		(78)
Changes in enacted tax rates		2		(58)
Prior year's charges in current expense		–		155
Capital taxes		120		116
Other		–		1
Total income and capital taxes	$	1,529	$	1,304

Total income taxes are comprised of:

($000s)		2005		2004
Current income and capital taxes	$	1,105	$	1,147
Future taxes		424		157
Total income and capital taxes	$	1,529	$	1,304

The components of Freehold Resources' future income taxes at December 31 are as follows:

($000s)		2005		2004
Future income tax liabilities:				
Petroleum and natural gas interests	$	5,288	$	4,831
Future income tax assets:				
Asset retirement		(1,356)		(1,324)
Net future income tax liability	$	3,932	$	3,507

10. SUPPLEMENTAL CASH FLOW DISCLOSURE

CHANGES IN NON-CASH WORKING CAPITAL BALANCE

($000s)		2005		2004
Accounts receivable	$	(22,931)	$	(1,168)
Accounts payable and accrued liabilities		1,941		776
Working capital from corporate acquisition		–		180
	$	(20,990)	$	(212)

CASH EXPENSES PAID

($000s)		2005		2004
Interest	$	3,301	$	643
Taxes		1,465		808

NINE-YEAR HISTORICAL REVIEW

	2005	2004	2003	2002	2001	2000	1999	1998	1997
Financial									
($000s, except as noted)									
Gross revenue	**136,914**	78,491	73,166	63,143	61,885	64,500	36,355	24,839	39,953
Funds generated from operations	**118,034**	64,313	60,658	51,489	49,728	51,882	27,304	15,210	30,797
Per Trust Unit *($)*	**2.76**	2.04	1.95	1.71	1.72	1.94	1.03	0.57	1.16
Net income [1]	**58,346**	36,892	37,078	27,529	27,304	31,758	8,714	(9,278)	3,045
Per Trust Unit *($)*	**1.36**	1.17	1.19	0.91	0.95	1.19	0.33	(0.35)	0.12
Distributions	**84,810**	54,490	53,149	39,530	45,264	35,226	20,757	17,186	29,081
Per Trust Unit *($)*	**1.92**	1.73	1.70	1.31	1.56	1.32	0.78	0.65	1.10
Development expenditures	**7,982**	5,823	5,894	2,946	2,992	5,161	940	1,790	2,613
Acquisitions	**351,705**	13,061	3,386	2,326	29,707	5,326	–	–	27,407
Long-term debt	**107,000**	27,000	18,000	30,000	33,000	38,000	39,288	39,288	38,175
Unitholders' equity	**399,471**	164,822	180,992	185,326	196,317	182,898	185,742	197,346	233,261
Operating									
Production									
Oil *(bbls/d)*	**4,488**	3,594	3,688	3,926	3,873	3,353	2,921	3,208	3,566
NGL *(bbls/d)*	**345**	283	317	288	354	327	302	339	347
Natural gas *(MMcf/d)*	**16.8**	10.3	10.9	10.7	11.2	11.0	11.2	11.9	15.5
Oil equivalent *(boe/d)*	**7,636**	5,588	5,817	6,004	6,086	5,523	5,082	5,531	6,493
Average sales price									
Oil *($/bbl)*	**46.65**	38.08	32.77	31.25	24.42	32.98	21.82	12.91	19.22
NGL *($/bbl)*	**50.58**	37.29	30.95	25.09	29.91	32.81	16.94	13.82	19.02
Natural gas *($/Mcf)*	**8.55**	6.28	6.18	3.81	5.64	4.71	2.48	1.91	1.79
Oil equivalent *($/boe)*	**48.53**	37.91	34.01	28.44	27.63	31.39	18.99	12.45	15.84
Operating netback *($/boe)*	**45.49**	34.05	30.51	25.43	24.30	28.26	17.10	9.94	14.63
Undeveloped land *(gross acres)*	**555,171**	291,729	242,205	235,062	237,443	140,896	136,036	132,609	77,906
Reserves *(Mboe)* [2]	**30,530**	21,163	22,052	26,813	28,177	28,150	29,062	29,952	30,809
Reserve life index *(years)*	**9.9**	10.6	11.0	12.2	12.7	14.0	15.7	14.8	13.0
Trust Unit									
High *($)*	**19.30**	18.42	17.19	11.35	10.10	9.50	6.90	9.80	11.85
Low *($)*	**14.25**	14.02	10.50	9.00	8.00	5.60	4.13	4.15	8.40
Close *($)*	**18.81**	17.45	16.35	10.88	9.20	8.70	5.95	4.43	9.10
Volume *(000s)*	**28,320**	11,567	10,970	7,323	8,162	6,752	5,782	9,686	11,392
Outstanding, end of year *(millions)*	**49.0**	31.5	31.5	30.2	30.1	26.7	26.6	26.6	26.5
Weighted average *(millions)*	**42.8**	31.5	31.2	30.2	28.8	26.7	26.6	26.5	26.4

1 2003 and prior years restated.
2 The reserves data for 2003-2005 is not directly comparable to data for the years 1996 through 2002 due to new reserve definitions and evaluation methodology that came into effect in 2003. Reserves for 2003-2005 were evaluated under National Instrument 51-101 and are reported as net proved plus probable reserves. Previously, reserves were evaluated under National Policy 2-B and reported as gross (before royalties) proved plus half probable (established) reserves.

FOR CANADIAN RESIDENTS

For purposes of the Income Tax Act (Canada), Freehold Royalty Trust is treated as a mutual fund trust. Each year, we file a T3 income tax return with the taxable income allocated to and made taxable in the hands of Unitholders. This taxable income is allocated, on T3 supplementary forms, to each Unitholder who was entitled to distributions for the year. The T3 slip will report the amount in Box 26. This income is taxed as ordinary income.

2005 CANADIAN TAX INFORMATION

Record Date	Payment Date	Taxable Amount Box 26 (Other Income) *(Cdn$ per Unit)*	Tax-Deferred Amount (Return of Capital) *(Cdn$ per Unit)*	**Total Distribution Paid** *(Cdn$ per Unit)*
December 31, 2004	January 15, 2005	0.12	0.00	**0.12**
January 31, 2005	February 15, 2005	0.12	0.00	**0.12**
February 28, 2005	March 15, 2005	0.17	0.00	**0.17**
March 31, 2005	April 15, 2005	0.12	0.00	**0.12**
April 30, 2005	May 15, 2005	0.12	0.00	**0.12**
May 31, 2005	June 15, 2005	0.17	0.00	**0.17**
June 30, 2005	July 15, 2005	0.12	0.00	**0.12**
July 31, 2005	August 15, 2005	0.12	0.00	**0.12**
August 31, 2005	September 15, 2005	0.20	0.00	**0.20**
September 30, 2005	October 15, 2005	0.14	0.00	**0.14**
October 31, 2005	November 15, 2005	0.14	0.00	**0.14**
November 30, 2005	December 15, 2005	0.24	0.00	**0.24**
December 31, 2005	January 15, 2006	0.18	0.00	**0.18**
February 20, 2006	March 15, 2006	0.08	0.00	**0.08**[1]
Total paid or payable in 2005		2.04	0.00	**2.04**

1 Additional distribution payable in respect of 2005 income.

Adjusted Cost Base Calculation for Capital Gains Purposes

Unitholders are required to reduce the adjusted cost base (ACB) of their Trust Units by the amount equal to any distributions received in the form of return of capital (the tax-deferred portion of distributions received). Unitholders should maintain a record of all distributions that are classified as partially or entirely a return of capital distribution while holding Freehold Trust Units. For Freehold investors in the $10 per Trust Unit initial public offering in November 1996, the ACB of Trust Units still held as at December 31, 2005 is $3.5284 per Trust Unit, taking into account the cumulative return of capital of $6.4716 as provided in the following table.

HISTORICAL CANADIAN TAX INFORMATION

Year	Taxable Amount (Other Income) *(Cdn$ per Unit)*	Tax Deferred Amount [1] (Return of Capital) *(Cdn$ per Unit)*	Taxable Percentage	Tax Deferred Percentage	Total Distribution Paid *(Cdn$ per Unit)*
2005	**2.04**	**0.00**	**100%**	**0%**	**2.04**
2004	1.1628	0.5472	68%	32%	1.71
2003	1.1730	0.5270	69%	31%	1.70
2002	0.7598	0.5502	58%	42%	1.31
2001	0.5928	0.9672	38%	62%	1.56
2000	0.00	1.2900	0%	100%	1.29
1999	0.00	0.7600	0%	100%	0.76
1998	0.00	0.8500	0%	100%	0.85
1997	0.00	0.9800	0%	100%	0.98
Total	**5.7284**	**6.4716**			**12.20**

1 The tax-deferred amount reduces the adjusted cost base of a Unitholder's investment in Freehold.

FOR NON-RESIDENTS OF CANADA

Unitholders who are not residents of Canada for income tax purposes are encouraged to seek advice from a qualified tax advisor in their country of residence for the tax treatment of distributions.

Distributions paid or payable to non-residents of Canada are subject to a withholding tax of 25% as prescribed by the Income Tax Act (Canada). This withholding tax may be reduced in accordance with reciprocal tax treaties. In the case of the Tax Treaty between Canada and the U.S., the withholding tax for U.S. residents is prescribed at 15%.

FOR UNITED STATES RESIDENTS

Freehold's 2005 Income Tax Information for U.S. Investors is filed on Freehold's website at www.freeholdtrust.com. For Trust Units held outside a qualified retirement plan, 100% of the distributions should be reported as ordinary dividends unless the Unitholder elects to treat Freehold as a Qualified Electing Fund (see below), in which case the Unitholder's share of income should be reported as ordinary income.

Passive Foreign Investment Company

In consultation with its U.S. tax advisors, Freehold believes that it should be classified as a passive foreign investment company ("PFIC") under U.S. federal income tax principles. As such, distributions made during 2005 are subject to the regimes of U.S. federal income taxation applicable to PFICs.

Qualified Electing Fund Regime

Freehold, in order to allow Unitholders the ability to make a QEF election, posts annually a PFIC Annual Information Statement on its website. Unitholders should contact their own tax advisors for information on correctly completing Form 8621. This information is not available from Freehold.

Form 1099-DIV "Dividends and Distributions"

U.S. individual Unitholders who hold their Freehold Trust Units through a stockbroker or other intermediary should receive tax reporting information from their stockbroker or other intermediary. We expect that the stockbroker or other intermediary will issue a Form 1099-DIV, "Dividends and Distributions" or a substitute form developed by the stockbroker or other intermediary. Freehold is not required to furnish such Unitholders with Form 1099-DIV. Information on the Forms 1099-DIV issued by the brokers or other intermediaries may not accurately reflect the information in Freehold's summary for a variety of reasons. Investors should consult their brokers and tax advisors to ensure that the information presented is accurately reflected on their tax returns. Brokers and/or intermediaries may not be required to issue amended Forms 1099-DIV.

+ UNITHOLDER INFORMATION

Please visit www.freeholdtrust.com for annual and quarterly reports, news releases, corporate presentations, a glossary of oil and gas terms, FRU.UN trading history and information on distributions and Unitholder taxation.

Distribution Policy and Dates

We make regular monthly distributions, the amounts of which are determined by the board of directors and subject to change depending upon the business environment. Record dates are the end of each month, and payment dates are the fifteenth day of the following month.

2006 Reporting Calendar

Feb. 22: Fourth quarter and 2005 year-end results
May 10: First quarter results
Aug. 9: Second quarter results
Nov. 8: Third quarter results

Unitholder Plans

Direct Deposit Plan:
A Direct Deposit Plan is in place to provide Unitholders who have Canadian bank accounts with a method of receiving cash distributions as a direct deposit into their bank accounts.

Distribution Reinvestment Plan (DRIP):
A DRIP is in place to provide Unitholders who are residents of Canada with a method of reinvesting cash distributions into new Trust Units.

U.S. Currency Payment Plan:
Unitholders may elect to receive their distribution payments in U.S. funds.

Annual and Special Meeting of Unitholders

The Annual and Special Meeting of Unitholders will be held on Wednesday, May 10, 2006, at 3:30 p.m. in the Lecture Theatre, Sunlife Plaza Conference Centre, Plus 15 (2nd level), 140 – 4 Avenue S.W., Calgary, Alberta.

Trustee and Transfer Agent

For information about distribution cheques, Trust Unit certificates, transfers, duplicate mailings and address changes, please contact:

Computershare Trust Company of Canada
710, 530 – 8 Avenue SW
Calgary, Alberta T2P 3S8
or
100 University Avenue
9th Floor
Toronto, Ontario M5J 2Y1

Toll Free: 1-800-564-6253
Fax: 1-888-453-0330
www.computershare.com
Email inquiries: service@computershare.com

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Stock Exchange Listing

Toronto Stock Exchange
Symbol: FRU.UN

Trustee and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta and Toronto, Ontario

Legal Counsel

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

Auditors

KPMG LLP
Calgary, Alberta

Bankers

Canadian Imperial Bank of Commerce
Calgary, Alberta

Royal Bank of Canada
Calgary, Alberta

Evaluation Engineers

Trimble Engineering Associates Ltd.
Calgary, Alberta

Board of Directors

William W. Siebens [2]

D. Nolan Blades [1, 2, 3]

Harry S. Campbell, Q.C. [3]

Tullio Cedraschi

Peter T. Harrison [1, 3]

Dr. P. Michael Maher [1, 2]

David J. Sandmeyer

1 Audit Committee
2 Governance Committee
3 Reserves Committee

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Vice-President, Exploitation

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Controller

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Vice-President, Production

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